IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB	 Judge Bernard A. Friedman Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.)))
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)))
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

APPENDIX A

INDEX OF EXHIBITS

Exhibit Number	Description
1	United States v. Cinergy Corp., 1:99-cv-01693-LJM-JMS (S.D. Ind.), Final Jury Instructions, Dkt. 1335 (May 21, 2008)
2	Memo from Don Clay to David Kee re: Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to Wisconsin Electric Power Company Port Washington Life Extension Project (Sept. 9, 1988)
3	Compendium of Documents re: EPA Applications of the Routine Maintenance Exception (contains documents A-L)

4	Letter from Francis Lyons to Henry Nickel re: applicability determination for Detroit Edison's "Dense Pack" project at Monroe Power Plant (May 23, 2000)
5	Michigan New Source Review Program Review performed by U.S. EPA Region 5 (August 2004)
6	In re Tennessee Valley Authority, CAA Docket No. 00-6, Final Order on Reconsideration (Sept. 15, 2000)
7	Memo from John Rasnic to George Czerniak re: Applicability of New Source Review Circumvention Guidance to 3M - Maplewood, Minnesota (June 17, 1993)
8	Letter from Dianne McNally to Mark Wejkszner re: Northampton PSD/NSR Analysis (Apr. 20, 2010)
9	PSD Workbook, A Practical Guide to Prevention of Significant Deterioration, Michigan Dept. of Envtl. Quality (October 2003) (Excerpt)

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)
) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
)
Plaintiff-Intervenors)
v.	
)
DTE ENERGY COMPANY, and)
DETROIT EDISON COMPANY)
)
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 1

UNITED STATES DISTRICT COURT SOUTHERN DISTRICT OF INDIANA INDIANAPOLIS DIVISION

UNITED STATES OF AMERICA, Plaintiff,)
STATE OF NEW YORK, STATE OF NEW JERSEY, STATE OF CONNECTICUT, HOOSIER ENVIRONMENTAL COUNCIL, and OHIO ENVIRONMENTAL COUNCIL, Plaintiff-Intervenors,	•
VS.) 1:99-cv-1693-LJM-JMS
PSI ENERGY, INC. and THE CINCINNATI GAS & ELECTRIC COMPANY, Defendants.))))

FINAL JURY INSTRUCTIONS

INSTRUCTION NO. _1_

Members of the jury, the evidence and arguments in this case have been completed, and I will now instruct you as to the law applicable to this case. It is your duty to follow all of the instructions.

You must not question any rule of law stated in these instructions. Regardless of any opinion you may have as to what the law ought to be, you must base your verdict upon the law as it is set out herein.

It is your duty to determine the facts from the evidence in this cause. You are to apply the law given to you in these instructions to the facts and in this way decide the case.

Unless you are otherwise instructed, the evidence in the case always consists of the sworn testimony of the witnesses, regardless of who may have called them; all exhibits received in evidence, regardless of who may have produced them; and all facts which may have been admitted or stipulated.

Any evidence to which an objection was sustained by the Court, and any evidence ordered stricken by the Court, must be entirely disregarded.

The burden is on the plaintiffs, and on the defendants for any affirmative defense, to prove every essential element of the case by a preponderance of all of the evidence. A preponderance of the evidence is evidence which, when considered and compared with that opposed to it, has more convincing force and produces in your minds a belief that what is sought to be proven is more likely true than not true. Your verdict may not be based on mere speculation.

If the proof fails to establish any essential element of plaintiffs' case by a preponderance of the evidence, or if the evidence on any essential element thereof is equally balanced, then you should find for the defendants.

I will hereafter use the phrase "if you find." Such phrase means "if you find from a preponderance of all the evidence," as just defined.

The law of this case is contained in these Instructions, considered as a whole. You are bound by your oath to follow the law.

Your job is to determine the facts. Do so without bias or prejudice against, or sympathy for, either party. All persons, individuals and corporations alike, stand equal before the law and are to be dealt with as equals in the court of justice. You therefore must consider this case as an action between persons of equal standing in the community, of equal worth, and holding similar stations in life.

INSTRUCTION NO. _5_

You are the sole judges of the credibility -- that is, the believability -- of the witnesses. Reconcile their testimony on the theory that all are accurate and truthful, if you can; but if you cannot, then you must determine whom you will believe and whom you will not believe and what is the truth.

In determining the credibility of the witnesses, you may take into consideration their interest or lack of interest in the result of this suit; their manner and bearing on the witness stand; their means or lack of means of knowing the facts about which they have testified; how far, if at all, they are either supported or contradicted by other evidence; their power of memory or the lack thereof; inconsistent statements made by them, if any; and from all the evidence you will give to each witness the credit to which he or she is entitled.

Inconsistencies or discrepancies in the testimony of a witness, or between the testimony of different witnesses, may or may not cause the jury to discredit such testimony. Two or more persons witnessing an incident or a transaction may see or hear it differently; and innocent mis-recollection, like failure of recollection, is not an uncommon experience. In weighing the effect of any discrepancy, you may consider whether it pertains to a matter of importance or an unimportant detail, and whether the discrepancy results from innocent error or intentional falsehood.

The testimony of a witness may be discredited or impeached by contradictory evidence, or by proving that he or she previously made a statement inconsistent with his or her present testimony. Before you could consider a witness to have been impeached on the basis of an earlier contradictory statement, you would, of course, first have to find as a fact that such statement was indeed made by the witness and that it in fact contradicts his or her present testimony, considering all of the circumstances under which you find it to have been made.

If you believe any witness has been impeached, and thus discredited, or has knowingly testified falsely concerning any material matter, you have a right to distrust such witness's testimony in other particulars; and you may reject all the testimony of that witness or give such credibility as you may think it deserves.

INSTRUCTION NO. _7__

The weight to be given to any particular evidence is not necessarily determined by the number of witnesses testifying on behalf of each side. You are to consider all the evidence in the case in determining the credibility of the witnesses. You may find that the testimony of a smaller number of witnesses for one side is more credible, and hence deserving of more weight, than the testimony of a greater number of witnesses for the other side.

INSTRUCTION NO. _8_

There are, generally speaking, two types of evidence. One is direct evidence, such as the testimony of an eyewitness. The other is indirect or circumstantial evidence, that is, proof of a certain fact or facts from which you reasonably may deduce another fact. In other words, circumstantial evidence is that by which proof of one fact also tends to prove another, according to the common experience of mankind.

The law makes no distinction between the two, but simply requires that the jury find the facts in accordance with all the evidence, both direct and circumstantial.

You should use your common sense in weighing the evidence and consider the evidence in light of your own observations in life.

In our lives, we often look at one fact and conclude from it that another fact exists. In law we call this an "inference." A jury is allowed to make reasonable inferences. Any inferences you make must be reasonable and must be based on the evidence in the case.

Neither by these instructions, nor by any ruling or remark which I have made, do I mean to indicate any opinion as to the facts or as to what your verdict should be. You are the sole and exclusive judges of the facts.

INSTRUCTION NO. _11_

The evidence from which you will find the facts consists of the testimony of witnesses, documents and other things received into the record as exhibits, and any facts the parties agree or stipulate to, or that the court may instruct you to find.

You are to consider only the evidence received in this case. You should consider this evidence in light of your own observations and experiences in life. You may draw such reasonable inferences as you believe to be justified from proven facts.

Certain things are not evidence and must not be considered by you. I will list them for you now:

- 1. Statements, arguments, and questions by counsel are not evidence.
- 2. Objections to questions are not evidence. The parties were entitled to make an objection when they believe evidence being offered is improper under the rules of evidence. You should not be influenced by the objection or by the Court's ruling on it. If the objection was sustained, ignore the question. If it was overruled, treat the answer like any other.
- 3. Testimony that the Court has excluded or told you to disregard is not evidence and must not be considered.
- 4. Anything you may have seen or heard outside the courtroom is not evidence and must be disregarded. You are to decide the case solely on the evidence presented here in the courtroom.

Certain demonstrative exhibits such as photographs and charts have been shown to you. Such demonstrative exhibits are used for convenience and to help explain the facts of the case. They are not themselves evidence.

The sworn testimony of several witnesses was taken by deposition prior to this trial. The testimony of a witness who for some proper reason cannot be present to testify in person may be presented in this form. Such testimony is given under oath and in the presence of the attorney for the parties, who question the witness. A stenographer records the testimony in a transcript so that you may later hear the questions asked and the answers given. Some of this sworn testimony was presented by reading the transcript to you; some of this sworn testimony was presented to you by videotape. You must consider this evidence in the same light and subject to the same tests that apply to testimony of other witnesses.

During the trial, you heard the testimony of expert witnesses. This testimony is admissible where the subject matter involved requires knowledge, special study, training, or skill not within ordinary experience, and the witness is qualified to give an expert opinion.

However, the fact that an expert has given an opinion does not mean that you are bound by the opinion, or that you are obligated to accept the opinion as to the facts. You should assess the weight to be given to the expert opinion in light of all the evidence in the case.

The law does not require any party to call as a witness every person who might have knowledge of the facts related to this trial. Similarly, the law does not require any party to present as exhibits all papers and things mentioned during this trial.

SUMMARY OF THE CLAIMS

This is a civil case brought by the plaintiffs, who are the United States; the States of New York, New Jersey, and Connecticut; and two groups representing local citizens, Hoosier Environmental Council and Ohio Environmental Council. Plaintiffs allege that the defendants, PSI Energy, Inc. and the Cincinnati Gas & Electric Company, violated the New Source Review program, or the "NSR program," of the Clean Air Act and similar programs under Indiana and Ohio state law. The Clean Air Act gives citizens and states the right to bring suit to enforce the provisions of the Act, which includes the New Source Review program.

In enacting the New Source Review program, Congress had several purposes in mind. Specifically, the stated purposes of the program are (1) "to protect public health and welfare from any actual or potential adverse effect . . . from air pollution"; (2) "to preserve, protect, and enhance the air quality" in national parks and similar areas of "national or regional natural, recreational, scenic, or historic value"; (3) "to [e]nsure that economic growth will occur in a manner consistent with the preservation of existing clean air resources"; (4) to assure that emissions from a source in one state do not interfere with a plan "to prevent significant deterioration of air quality" in another state; and (5) to assure that a decision to allow increased air pollution to occur in an area "is made only after careful evaluation of all the consequences of such a decision" and after an opportunity for public participation in the decisionmaking process. 42 U.S.C. § 7470.

INSTRUCTION NO. 16, continued

In order to achieve the goals of the New Source Review program, both the federal and state New Source Review programs require sources of air pollution, such as power plants, to obtain a permit and install pollution controls when plants are constructed or when they go through any changes that reasonably might be expected to increase emissions above certain prescribed limits. Such changes are known as major modifications.

In this case, Plaintiffs contend that Defendants violated both the federal and state New Source Review programs by failing to comply with the requirements pertaining to permits and pollution controls before undertaking several construction projects at five different power plants. The specific projects at issue are as follows:

Project #1:	Life extension project at Beckjord unit 1 from November 1987 to February 1988;
Project #2	Life extension project at Beckjord unit 2 from October 1987 to January 1988;
Project #3	Life extension project at Beckjord unit 3 from October 1985 to January 1986;
Project #4	Condensor retubing at Beckjord unit 5 from January 1991 to February 1991;
Proejct #5	Condensor retubing at Beckjord unit 6 from September 1994 to November 1994;
Project #6	Replacement of the pulverizers at Gallagher unit 1 from April 1998 to July 1998;

INSTRUCTION NO. 16, continued

Project #7	Condensor retubing at Gallagher unit 2 from August 1990 to December 1990;
Project #8	Replacement of the pulverizers at Gallagher unit 3 from February 1999 to April 1999;
Project #9	Replacement of the reheater tube section at Gibson unit 2 from February 2001 to May 2001;
Project #10	Replacement of the slope tubes and lower headers at Miami Fort unit 5, January 1995 to March 1995;
Project #11	Replacement of the front wall radiant superheater at Wabash River unit 2 from June 1989 to July 1989;
Project #12	Replacement of the high temperature finishing superheater tubes and upper reheater tubing assemblies at Wabash River unit 2 from May 1992 to September 1992;
Project #13	Replacement of the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles at Wabash River unit 3 from June 1989 to October 1989; and
Project #15	Replacement of the boiler pass and heat recovery actions at Wabash River unit 5 from February 1990 to May 1990.

MAJOR MODIFICATION

In this case, you must consider each project at issue and determine whether it is a major modification. The definition of a major modification has several components. The first and simplest definition is that a major modification is any physical change that increases the amount of air pollutant emitted above certain prescribed limits. The air pollutants involved in this case are sulfur dioxide and nitrogen oxides.

For each project, Plaintiffs have the burden of proving by a preponderance of the evidence that the project was a major modification. You must give separate consideration to each project in this case. In considering whether a project is a major modification, you must answer two questions that further define the term major modification:

- 1. Was there a physical change at a generating unit?
- 2. Should a reasonable power plant owner or operator have expected the physical change to result in a significant net increase in emissions, specifically for this case, an increase in either sulfur dioxide or nitrogen oxides?

Additional instructions for answering these two questions follow.

INSTRUCTION NO. 18

PHYSICAL CHANGE

The definition of a physical change is broad. There is no requirement that a project be a certain size or meet a certain cost threshold to be defined as a physical change. A physical change can consist of the repair and replacement of a single component, and can include the replacement of a piece of equipment with a new version of the same equipment. Certain activity, however, is excluded from the term physical change. Specifically, the activity that is excluded is known as routine maintenance, repair, and replacement, or "RMRR."

As a defense to the Plaintiffs' claims in this case, Defendants have alleged that some of their projects were routine maintenance, repair, and replacement activity and therefore not a physical change. It is Defendants' responsibility to prove that the projects qualify as routine maintenance, repair, and replacement. Therefore, you must find that a project was not routine maintenance, repair, and replacement unless Defendants prove by a preponderance of the evidence that a project qualifies as routine maintenance, repair, and replacement. If Defendants fail to satisfy that burden, you should conclude that a project does not qualify as routine maintenance, repair, and replacement activity and instead is a physical change. You should then proceed to the next question, whether a reasonable power plant owner or operator would have expected that physical change to result in a significant net increase in emissions.

On the other hand, if you find that Defendants have proved by a preponderance of the evidence that a particular project qualifies as routine maintenance, repair, and replacement, you must find Defendants not liable on that project.

INSTRUCTION NO. 19

ALLEGED ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT ACTIVITY

You will not have to decide the issue of physical change or RMRR activity for all projects. Instead, you will only have to consider that issue for the projects that Defendants allege were RMRR activity. Those projects are as follows:

Project #4	Condensor retubing at Beckjord unit 5 from January 1991 to February 1991;	
Project #5	Condensor retubing at Beckjord unit 6 from September 1994 to November 1994;	
Project #11	Replacement of the front wall radiant superheater at Wabash River unit 2 from June 1989 to July 1989;	
Project #12	Replacement of the high temperature finishing superheater tubes and upper reheater tubing assemblies at Wabash River unit 2 from May 1992 to September 1992;	
Project #13	Replacement of the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles at Wabash River unit 3 from June 1989 to October 1989; and	
Project #15	Replacement of the boiler pass and heat recovery actions at Wabash River unit 5 from February 1990 to May 1990.	

For each of the projects that Defendants have alleged involved RMRR activity, you must determine whether the particular project actually was RMRR activity.

ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT ANALYSIS

In making your determination on whether a project constitutes RMRR activity, you should keep in mind that the RMRR exclusion applies to a narrow range of activities. Further, in deciding whether a project is RMRR, you may consider:

- the nature of the project;
- the extent of the work performed;
- the purpose of the project;
- how frequently the project is performed at the facility;
- how frequently the type of project is performed within the industry at other facilities; and
- the cost of the project.

No single factor is dispositive. Instead, for each project, you should consider the circumstances as a whole when making your determination on whether the project was RMRR activity.

SIGNIFICANT NET EMISSIONS INCREASES

After you have completed your RMRR analysis for the six projects listed in Instruction No. 19, you must address a second question for any project that you decided was not RMRR and for the remaining projects for which Defendants have not asserted the RMRR defense. Specifically, you must determine whether a reasonable power plant owner or operator would have expected a project to result in a significant net increase in emissions. A significant net increase is one that would be expected to result in a net increase of an air pollutant of 40 or more tons per year.

In this case, the pollutants are sulfur dioxide and nitrogen oxides. In considering whether a reasonable power plant owner or operator would have expected a project to result in a significant net increase in emissions, you must evaluate each of these pollutants individually at each project under consideration.

If a project was not RMRR and you conclude that a reasonable owner or operator should have expected a project to result in a significant net increase of 40 or more tons per year in sulfur dioxide or nitrogen oxides emissions, you should find that the project was a major modification and, consequently, your verdict should be for Plaintiffs.

If, on the other hand, a project was not RMRR and you conclude that a reasonable owner or operator should not have expected a project to result in a significant net increase of 40 or more tons per year in sulfur dioxide or nitrogen oxides emissions, you should find that the project was not a major modification and, consequently, your verdict should be for Defendants.

PROJECTS REQUIRING AN EMISSIONS DETERMINATION

You must make a determination on significant net emissions increases for each of the projects that you concluded was not RMRR and for each of the following projects:

Project #1	Life extension project at Beckjord unit 1 from November 1987 to February 1988;
Project #2	Life extension project at Beckjord unit 2 from October 1987 to January 1988;
Project #3	Life extension project at Beckjord unit 3 from October 1985 to January 1986;
Project #6	Replacement of the pulverizers at Gallagher unit 1 from April 1998 to July 1998;
Project #7	Condensor retubing at Gallagher unit 2 from August 1990 to December 1990;
Project #8	Replacement of the pulverizers at Gallagher unit 3 from February 1999 to April 1999;
Project #9	Replacement of the reheater tube section at Gibson unit 2 from February 2001 to May 2001; and
Project #10	Replacement of the slope tubes and lower headers at Miami Fort unit 5, January 1995 to March 1995.

ANALYSIS FOR SIGNIFICANT NET EMISSIONS INCREASES

Your consideration of whether a reasonable owner or operator should have expected a project to result in a significant net increase in emissions is not dependent upon whether emissions actually increased after a project. The law requires an owner or operator to make an assessment or prediction on that question before the project begins. Therefore, you must look to the information available to Defendants at the time that they began a project and decide whether a reasonable owner or operator should have predicted that a project would have caused a net increase of 40 or more tons per year in sulfur dioxide or nitrogen oxide emissions. You should consider all relevant information available to Defendants at the time of the project, including prior operating data and Defendants' own statements and documents.

In making your determination, you should compare the emissions per year before a project began to the emissions predicted to result from the project. To do so, you must look at a reasonable baseline period which is representative of normal operations before a project was performed. In this case, for projects started before July 21, 1992, the proper baseline period is the 24 months immediately prior to the start of the project. For projects that started after July 21, 1992, the proper baseline period can be any 24-month period within the 5 years preceding the project as long as you are comfortable that the period is representative of the normal operation of a unit during those 5 years.

INSTRUCTION NO. 23, continued

As a final matter, in making your determination you should exclude from your consideration a change in emissions that is unrelated to a physical change, that is, to the project itself. For instance, an increase that is unrelated to a physical change and instead is attributable to a growth in demand for electricity should be excluded. Such an exclusion is sometimes referred to as the "demand growth exclusion." The demand growth exclusion applies to emissions increases that could have been predicted or projected regardless of whether a physical change was to occur.

The burden is on Defendants to prove by a preponderance of the evidence that the demand growth exclusion applies to an emissions increase. In doing so, Defendants must demonstrate that the following two factors apply to the increase:

- 1. the unit could have accommodated the increase in emissions before the physical change; and
- 2. the increase is unrelated to the physical change.

Your job as jurors in this case is to decide whether Defendants are liable for the claims asserted against them. Include in your consideration whether Defendants, in fact, complied with the law, not whether they intended to comply. In deciding whether Defendants are liable, you should not be concerned about the question of damages or whether any harm may have resulted from the alleged violations; that is the Court's role after you have reached a decision on liability. You should only concern yourselves with deciding whether the RMRR exclusion has been met for those projects for which Defendants have asserted this defense and whether significant net emissions increases were likely to result from the Defendants' projects as those questions have been outlined for you.

During this trial I permitted you to take notes. Many courts do not permit note-taking by jurors, and a word of caution is in order. There is always a tendency to attach undue importance to matters that one has written down. Some testimony that is considered unimportant at the time presented, and thus not written down, takes on greater importance later in the trial in light of all the evidence presented. Therefore, you are instructed that your notes are only a tool to aid your own individual memory and you should not compare your notes with those of other jurors in determining the content of any testimony or in evaluating the importance of any evidence. Your notes are not evidence, and are by no means a complete outline of the proceedings or a list of the highlights of the trial. Above all, your memory should be your greatest asset when it comes time to deliberate and render a decision in this case.

If you did takes notes, you must leave your notes in the jury room after your verdict has been returned.

It is necessary from this time until you are discharged to remain together in a group and in the charge of the Bailiff. You are not, during your deliberations, to talk with anyone, other than your fellow jurors and the Bailiff. Make known to him or her any of your wants, and if you wish to communicate with me place your questions in writing and the Bailiff will contact me if necessary.

When you go to the jury room, elect one of your number as foreperson. It is the duty of the foreperson to see that your discussions are orderly and that each juror has the opportunity to discuss and vote on each matter before you. The authority of the foreperson is otherwise the same as that of any other juror.

These Instructions are all in writing and I will send them to the jury room for your use in your deliberations upon your verdict. You will also be permitted to take the exhibits with you for your use in your deliberations. When you have arrived at your verdict, have the foreperson sign and date it and notify the Bailiff in whose charge you have been placed.

I do not anticipate that you will need to communicate with me. If you do, however, the only proper way is in writing, signed by the foreperson, or if he or she is unwilling to do so, by some other juror, and given to the Bailiff and he or she will communicate with me.

A Special Verdict Form has been prepared for you. You should fill out the Special Verdict Form as part of your deliberations.

(Special Verdict Form read)

In addition, a verdict form has been prepared for you.

(Verdict Form read)

Take these forms to the jury room and, when you have reached unanimous agreement on the verdicts, your foreperson will fill in, date and sign the forms and return the completed forms with you into open Court.

UNITED STATES DISTRICT COURT SOUTHERN DISTRICT OF INDIANA INDIANAPOLIS DIVISION

UNIT	ED STATES OF AMERICA, Plaintiff,))
STAT STAT HOOS	TE OF NEW YORK, TE OF NEW JERSEY, TE OF CONNECTICUT, SIER ENVIRONMENTAL COUNCIL, OHIO ENVIRONMENTAL COUNCIL, Plaintiff-Intervenors,	
	VS.) 1:99-cv-1693-LJM-JMS
THE	ENERGY, INC. and CINCINNATI GAS & ELECTRIC PANY, Defendants.))))
	SPECIAL VE	RDICT FORM
		DEFENDANTS ASSERT A R, AND REPLACEMENT DEFENSE
1.	Project #4: Condensor retubing a February 1991;	at Beckjord unit 5 from January 1991 to

If you answered yes, return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. If you answered no, then proceed to questions 1.b. and 1.c. below.

____ NO

project qualified as RMRR activity?

a.

____ YES

Did Defendants prove by a preponderance of the evidence that the

	b.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?		
		YES	NO	
	C.	have proven by a Plaintiffs prove by power plant owner	iny demand growth exclusion that you find Defendants preponderance of the evidence for this project, did a preponderance of the evidence that a reasonable r or operator would have expected a net increase in hissions of 40 tons or more per year as a result of the	
		YES	NO	
2.	If you answered yes to either question 1.b. or 1.c., return a verdict for Plaintiff on this project on the Verdict Form and proceed to the next project. If yo answered no to both questions 1.b. and 1.c., return a verdict for Defendants o this project on the Verdict Form and proceed to the next project. Project #5: Condensor retubing at Beckjord unit 6 from September 1994 t November 1994;			
	a.	Did Defendants p project qualified a	rove by a preponderance of the evidence that the s RMRR activity?	
		YES	NO	
	the V		eturn a verdict for Defendants on this project on oceed to the next project. If you answered no, then below.	
	b.	have proven by a Plaintiffs prove by power plant owner	iny demand growth exclusion that you find Defendants preponderance of the evidence for this project, did a preponderance of the evidence that a reasonable r or operator would have expected a net increase in ssions of 40 tons or more per year as a result of the	
		YES	NO	
	If you	u answered ves to	question 2 h return a verdict for Plaintiffs on this	

project on the Verdict Form and proceed to the next project. If you answered

3.

no to questions 2.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

	ct #11: Replacement of the from June 1989 to July	the front wall radiant superheater at Wab 1989;	ash River
a.	Did Defendants prove project qualified as RMR	by a preponderance of the evidence RR activity?	that the
	YES	NO	
the V		n a verdict for Defendants on this produced to the next project. If you answered 3.c. below.	
b.	have proven by a prep Plaintiffs prove by a pro power plant owner or o	emand growth exclusion that you find Deconderance of the evidence for this property of the evidence that a respected a net in so of 40 tons or more per year as a respected.	oject, did asonable crease in
	YES	NO	
c.	have proven by a preparation prove by a preparation prove by a preparation of the proventies of the pr	emand growth exclusion that you find Deconderance of the evidence for this proreponderance of the evidence that a respected a net into of 40 tons or more per year as a respected.	oject, did asonable crease in
	YES	NO	

If you answered yes to either question 3.b. or 3.c., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 3.b. and 3.c., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

 4. Project #12: Replacement of the high temperature finishing superheater tubing assemblies at Wabash River unit 2 from May 1992 September 1992; a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity? 				
Project qualified as RMRR activity? ———————————————————————————————————	4.	and u	ipper reheater tubing as	
If you answered yes, return a verdict for Defendants on this project the Verdict Form and proceed to the next project. If you answered no, th proceed to question 4.b. below. b. After considering any demand growth exclusion that you find Defendant have proven by a preponderance of the evidence for this project, and power plant owner or operator would have expected a net increase sulfur dioxide emissions of 40 tons or more per year as a result of the project? ———————————————————————————————————		a.		
the Verdict Form and proceed to the next project. If you answered no, the proceed to question 4.b. below. b. After considering any demand growth exclusion that you find Defendar have proven by a preponderance of the evidence for this project, or Plaintiffs prove by a preponderance of the evidence that a reasonal power plant owner or operator would have expected a net increase sulfur dioxide emissions of 40 tons or more per year as a result of the project? ———————————————————————————————————			YES	NO
have proven by a preponderance of the evidence for this project, of Plaintiffs prove by a preponderance of the evidence that a reasonal power plant owner or operator would have expected a net increase sulfur dioxide emissions of 40 tons or more per year as a result of the project? ———————————————————————————————————		the V	erdict Form and procee	ed to the next project. If you answered no, ther
If you answered yes to question 4.b., return a verdict for Plaintiffs on the project on the Verdict Form and proceed to the next project. If you answer no to question 4.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. 5. Project #13: Replacement of the finishing, intermediate, and radiates superheater tubes and upper reheat tube bundles at Wabash River unit 3 from June 1989 to October 1989; a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity? ———————————————————————————————————		b.	have proven by a pre Plaintiffs prove by a p power plant owner or sulfur dioxide emission	eponderance of the evidence for this project, did preponderance of the evidence that a reasonable operator would have expected a net increase in
project on the Verdict Form and proceed to the next project. If you answer no to question 4.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. 5. Project #13: Replacement of the finishing, intermediate, and radiate superheater tubes and upper reheat tube bundles at Wabash River unit 3 from June 1989 to October 1989; a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity? ———————————————————————————————————			YES	NO
superheater tubes and upper reheat tube bundles at Wabash River unit 3 fro June 1989 to October 1989; a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity? ———————————————————————————————————		projecto no to	ct on the Verdict Form a question 4.b., return	and proceed to the next project. If you answered a verdict for Defendants on this project on the
project qualified as RMRR activity? YES NO If you answered yes, return a verdict for Defendants on this project the Verdict Form and proceed to the next project. If you answered no, the proceed to questions 5.b. and 5.c. below. b. After considering any demand growth exclusion that you find Defendant have proven by a preponderance of the evidence for this project, or Plaintiffs prove by a preponderance of the evidence that a reasonal power plant owner or operator would have expected a net increase sulfur dioxide emissions of 40 tons or more per year as a result of the project?	5.	super	heater tubes and upper	
If you answered yes, return a verdict for Defendants on this project the Verdict Form and proceed to the next project. If you answered no, th proceed to questions 5.b. and 5.c. below. b. After considering any demand growth exclusion that you find Defendar have proven by a preponderance of the evidence for this project, or Plaintiffs prove by a preponderance of the evidence that a reasonal power plant owner or operator would have expected a net increase sulfur dioxide emissions of 40 tons or more per year as a result of the project?		a.	•	• • •
 the Verdict Form and proceed to the next project. If you answered no, the proceed to questions 5.b. and 5.c. below. b. After considering any demand growth exclusion that you find Defendar have proven by a preponderance of the evidence for this project, of Plaintiffs prove by a preponderance of the evidence that a reasonal power plant owner or operator would have expected a net increase sulfur dioxide emissions of 40 tons or more per year as a result of the project? 			YES	NO
have proven by a preponderance of the evidence for this project, or Plaintiffs prove by a preponderance of the evidence that a reasonal power plant owner or operator would have expected a net increase sulfur dioxide emissions of 40 tons or more per year as a result of the project?		the V	erdict Form and procee	ed to the next project. If you answered no, ther
YES NO		b.	have proven by a pre Plaintiffs prove by a p power plant owner or sulfur dioxide emission	ponderance of the evidence for this project, dic preponderance of the evidence that a reasonable operator would have expected a net increase in
			YES	NO

	c.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?
		YES NO
	on thi	answered yes to either question 5.b. or 5.c., return a verdict for Plaintiffs s project on the Verdict Form and proceed to the next project. If you red no to both questions 5.b. and 5.c., return a verdict for Defendants on oject on the Verdict Form and proceed to the next project.
6.		t #15: Replacement of the boiler pass and heat recovery actions at sh River unit 5 from February 1990 to May 1990;
	a.	Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity?
		YES NO
	the Ve	answered yes, return a verdict for Defendants on this project on erdict Form and proceed to the next section. If you answered no, then ed to questions 6.b. and 6.c. below.
	b.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?
		YES NO
	C.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?
		YES NO
	TE	provided yes to either question 6 h on 6 a return a yardist for

If you answered yes to either question 6.b. or 6.c., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next section. If you answered no to both questions 6.b. and 6.c., return a verdict for Defendants on this project on the Verdict Form and proceed to the next section.

REMAINING PROJECTS

7.	Project #1: Life extension project at Beckjord unit 1 from November 1987 to February 1988;				
	a.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?			
		YES NO			
	b.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?			
		YES NO			
	If you answered yes to either question 7.a. or 7.b., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 7.a. and 7.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.				
8.	Project #2: Life extension project at Beckjord unit 2 from October 1987 to January 1988;				
	a.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?			
		YES NO			
	b.	After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the			

project?

		YES		NO		
	on th answ	answered yes to eit is project on the Ve ered no to both ques roject on the Verdic	erdict Form a stions 8.a. an	and proceed to the d 8.b., return a vero	next project. lict for Defenda	If you
9.		ct #3: Life extensi ary 1986;	on project a	t Beckjord unit 3 fr	om October 1	985 to
	a.	have proven by a Plaintiffs prove by power plant owner	preponderar a preponder or operator	rowth exclusion thance of the evidence rance of the eviden would have expections or more per year.	for this projece that a reas ted a net incre	ect, did onable ease in
		YES		NO		
	b.	have proven by a Plaintiffs prove by power plant owner	preponderar a preponder or operator	rowth exclusion that nce of the evidence rance of the eviden would have expect tons or more per y	for this proje ce that a reas ted a net incre	ct, did onable ease in
		YES		NO		
	on th	answered yes to eit is project on the Ve ered no to both ques roject on the Verdic	erdict Form a tions 9.a. an	and proceed to the d 9.b., return a verd	next project. lict for Defenda	If you
10.		ct # 6: Replacement y 1998;	t of the pulve	rizers at Gallagher ι	ınit 1 from Apr	il 1998
	a.	have proven by a Plaintiffs prove by power plant owner	preponderar a preponder or operator	rowth exclusion that nce of the evidence ance of the eviden would have expect tons or more per ye	for this proje ce that a reas ted a net incre	ct, did onable ease in
		YES	•	NO		
	If you	ı answered yes to d	question 10.a	a., return a verdict	for Plaintiffs of	on this

project on the Verdict Form and proceed to the next project. If you answered

no to both questions 10.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

- 11. Project #7: Condensor retubing at Gallagher unit 2 from August 1990 to December 1990;
 - a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

YES NO

If you answered yes to question 11.a., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 11.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

- 12. Project # 8: Replacement of the pulverizers at Gallagher unit 3 from February 1999 to April 1999;
 - a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

YES NO

If you answered yes to question 12.a., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to question 12.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

- 13. Project #9: Replacement of the reheater tube section at Gibson unit 2 from February 2001 to May 2001;
 - a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

YFS	NO

If you answered yes to question 13.a., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 13.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

- 14. Project # 10: Replacement of the slope tubes and lower headers at Miami Fort unit 5, January 1995 to March 1995;
 - a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

YES	NC

If you answered yes to question 14.a., return a verdict for Plaintiffs on this project on the Verdict Form. If you answered no to both question 14.a., return a verdict for Defendants on this project on the Verdict Form.

Once you have completed all of the questions on this Special Verdict Form and filled out the Verdict Form, sign and date both this Special Verdict Form and the Verdict Form and inform the Bailiff that you have reached a verdict.

FOREPERSON	Date	

UNITED STATES DISTRICT COURT SOUTHERN DISTRICT OF INDIANA INDIANAPOLIS DIVISION

UNITED STATES OF AMERICA, Plaintiff,)
STATE OF NEW YORK, STATE OF NEW JERSEY, STATE OF CONNECTICUT, HOOSIER ENVIRONMENTAL COUNCIL and OHIO ENVIRONMENTAL COUNCIL Plaintiff-Intervenors,	• •
vs.) 1:99-cv-1693-LJM-JMS
PSI ENERGY, INC. and THE CINCINNATI GAS & ELECTRIC COMPANY,) C)
Defendants.)

VERDICT FORM

We, the Jury in the above-entitled action, unanimously find in favor of:

PROJECTS FOR WHICH DEFENDANTS ASSERT A ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT DEFENSE

Plaintiffs	Defendants	on Project #4, the condensor retubing project at Beckjord unit 5 from January 1991 to February 1991;
Plaintiffs	Defendants	on Project #5, the condensor retubing project at Beckjord unit 6 from September 1994 to November 1994;
Plaintiffs	Defendants	on Project #11, the front wall radiant superheater replacement project at Wabash River unit 2 from June 1989 to July 1989;

Plaintiffs	Defendants	on Project #12, the high temperature finishing superheater tubes and upper reheater tubing assemblies replacement project at Wabash River unit 2 from May 1992 to September 1992;
Plaintiffs	Defendants	on Project #13, the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles replacement project at Wabash River unit 3 from June 1989 to October 1989;
Plaintiffs	Defendants	on Project #15, the boiler pass and heat recovery actions replacement project at Wabash River unit 5 from February 1990 to May 1990;
	REMAINING	PROJECTS
Plaintiffs	Defendants	on Project #1, the life extension project at Beckjord unit 1 from November 1987 to February 1988;
Plaintiffs	Defendants	on Project #2, the life extension project at Beckjord unit 2 from October 1987 to January 1988;
Plaintiffs	Defendants	on Project #3, the life extension project at Beckjord unit 3 from October 1985 to January 1986;
Plaintiffs	Defendants	on Project #6, the pulverizers replacement project at Gallagher unit 1 from April 1998 to July 1998;
Plaintiffs	Defendants	on Project #7, the condensor retubing project at Gallagher unit 2 from August 1990 to December 1990;
Plaintiffs	Defendants	on Project #8, the pulverizers replacement project at Gallagher unit 3 from February 1999 to April 1999;
Plaintiffs	Defendants	on Project #9, the reheater tube section replacement project at Gibson unit 2 from February 2001 to May 2001; and
Plaintiffs	Defendants	on Project #10, the slope tubes and lower headers replacement project at

2018sev11939-01/-BA669B-\$WWI-DM6# DOOZ-Lime Fit 160305/18/11ed 05/24508f 415ag F @ 41Do 52243

	Miami Fort unit 5, January 1995 to March 1995.
FOREPERSON	Date

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and) NATURAL RESOURCES DEFENSE) COUNCIL, and SIERRA CLUB)	Judge Bernard A. Friedman Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors) v.)	
DTE ENERGY COMPANY, and) DETROIT EDISON COMPANY)	
Defendants.)	

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

APPENDIX A

INDEX OF EXHIBITS

Exhibit Number	Description
1	United States v. Cinergy Corp., 1:99-cv-01693-LJM-JMS (S.D. Ind.), Final Jury Instructions, Dkt. 1335 (May 21, 2008)
2	Memo from Don Clay to David Kee re: Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to Wisconsin Electric Power Company Port Washington Life Extension Project (Sept. 9, 1988)
3	Compendium of Documents re: EPA Applications of the Routine Maintenance Exception (contains documents A-L)

4	Letter from Francis Lyons to Henry Nickel re: applicability determination for Detroit Edison's "Dense Pack" project at Monroe Power Plant (May 23, 2000)
5	Michigan New Source Review Program Review performed by U.S. EPA Region 5 (August 2004)
6	In re Tennessee Valley Authority, CAA Docket No. 00-6, Final Order on Reconsideration (Sept. 15, 2000)
7	Memo from John Rasnic to George Czerniak re: Applicability of New Source Review Circumvention Guidance to 3M - Maplewood, Minnesota (June 17, 1993)
8	Letter from Dianne McNally to Mark Wejkszner re: Northampton PSD/NSR Analysis (Apr. 20, 2010)
9	PSD Workbook, A Practical Guide to Prevention of Significant Deterioration, Michigan Dept. of Envtl. Quality (October 2003) (Excerpt)

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)
) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors	
V.)
DTE ENERGY COMPANY, and)
DETROIT EDISON COMPANY)
)
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 2

operations below maximum potential such that the emissions increases necessary to trigger applicability would not occur. The WEPCO should discuss its plans in this regard with EPA. Third, regarding NSPS applicability to unit 1, additional information is necessary to determine whether a physical or operational change would occur.

Thus, although this memorandum will serve to answer many of the questions necessary to reaching final determinations, you should advise MEPCU that ultimately applicability depends upon changes in emissions after the renovations and whether the company decides to take the steps which would enable it to lawfully avoid coverage. Also, MSPS coverage of unit 1 can only be determined after an evaluation of the additional information regarding the work to be performed. In addition, as to MSPS, MEPCO should be advised to submit a formal request pursuant to 40 CFR 60.5 if it desires a final applicability determination.

As the need for further factual development here suggests, determinations of PSD and NSPS applicability are fact-specific, and must be made on a case-by-case basis. This memorandum provides a framework for analyzing the proposed changes at Port Mashington and gives EPA's views on relevant issues of legal interpretation. It should also be useful in assessing other so-called "life extension" projects in the future. However, any such project would need to be reviewed in light of all the facts and circumstances particular to it. Thus, a final decision regarding PSD and NSPS applicability here would not necessarily be determinative of coverage as to other life extension projects.

If you have any further questions regarding the discussion or conclusions in this memorandum, please have your staff contact David Solomon of the New Source Review Section at FTS 629-5375.

1. Background

As mentioned in your March 25 request, the five coal-fired units at Port Washington began operation in 1935, 1943, 1948, 1949, and 1950, respectively. Each unit was initially rated at 80 megawatts electrical output capacity. In recent years, however, the performance of the units began to deteriorate due to age-related degradation of the physical plant. In particular, inspections performed by a MEPCO consultant in 1984 revealed extensive cracks originating from the internal surfaces of the rear steam drums and boiler bank boreholes in units 2, 3, 4, and 5, creating significant safety concerns. Because of these safety concerns and other age-related problems, in 1985 the operating levels of units 2, 3, and 4 were reduced, and unit 5 was removed from service. As a result of the plant's deteriorating condition, the maximum rated physical capacities of units 1, 2, 3, and 4 at this time are 45, 65, 75, and 55 megawatts, respectively.

of maintaining the plant in its present condition. Rather, this is a highly unusual, if not unprecedented, and costly-project. Its purpose is to completely rehabilitate aging power generating units whose capacity has significantly deteriorated over a period of years, thereby restoring their original capacity and substantially extending the period of their utilization as an alternative to retiring them as they approach the end of their useful physical and economic life. The most important factors that would support these conclusions are outlined below.

a. The project would involve the replacement of numerous major components. The information submitted by MEPCO shows that the company intends to replace several components that are essential to the operation of the Port Mashington plant. In particular, as noted above, MEPCO would replace the rear steam drums on the boilers at units 2, 3, 4, and 5. According to MEPCO, these steam drums are a type of "header" for the collection and distribution of steam and/or water within the boilers. They measure 60 feet long, 50.5 inches in diameter, and 5.25 inches thick, and their replacement is necessary to continue operation of the units in a safe condition. In addition, at each of the emissions units, MEPCO plans to repair or replace several other integral components, including replacement of the air heaters at units 1, 2, 3, and 4. The MEPCO also plans to renovate major mechanical and electrical auxiliary systems and common plant support facilities. The MEPCO intends to perform the work over a 4-year period, utilizing successive 9-month outages at each unit.

In its July B, 1987 application for authority to renovate to the Public Service Commission of Wisconsin (PSC), WEPCO described the life extension project and explained its purpose and necessity. The WEPCO took care to distinguish the proposed renovation work from routine maintenance that did not require PSC approval, explaining that:

... [work items] falling into the category of repetitive maintenance that are normally performed during scheduled equipment outages do not require specific commission approval and, accordingly, are not included in this application.

Thus, WEPCO's own earlier characterization of this project supports a finding that the planned renovations are not routine.

b. The purpose of the project is to significantly enhance the present efficiency and capacity of the plant and substantially extend its useful economic life. In its application to the PSC, WEPCO pointed out that due to age-related deterioration, total plant capability had declined by 40 percent. The company noted that the currently planned retirement dates for the Port Washington units, as set forth in its Advance Plan filed with the State, ranged from 1992 to 1999. However, WEPCO asserted that "extensive renovation of the five units and the plant common facilities is needed if operation of the plant is to be continued." In any event, WEPCO stated that the renovation work would allow the Port Washington plant to generate power at its designed capacity until the year 2010, and thus "represents a life extension of the units."

diameter, and EPA does not believe that they are comparable in diameter, wall thickness, function, or importance to the rear steam drums at Port Washington.²

d. The work called for under the project is costly, both in relative and absolute terms. The latest information supplied by WEPCO is that the renovation work at Port Washington will cost \$87.5 million, of which at least \$45.6 million is designated as capital costs. The WEPCO reports that, in terms of annualized costs, the renovation project will cost \$7.8 million, as compared to \$51.6 million for a new 400 megawatt plant. Thus, renovation costs represent approximately 15 percent of replacements costs.

2. Change in the Method of Operation

The renovation work at Port Washington would not constitute a "change in the method of operation" within the meaning of the PSD regulations. However, it is clear that the "physical change" and "operational change" components of the "major modification" definition are discrete and independent. Thus, as explained below, PSD still applies if there is a physical change that will significantly increase net emissions.

In addition, the regulations exclude from the definition of physical or operational change "an increase in the hours of operation or in the production rate" [see 40 CFR 52.21(b)(2)(iii)(f)]. The preamble to the rule [45 FR 52676, 52704 (August 7, 1980)], makes it clear that this exclusion is intended to allow a company to lawfully increase emissions through a simple change in hours or rate of operation up to its potential to emit (unless already subject

The MEPCO's July 29, 1988 letter to EPA stated (on page 13) that after further investigation, the company "learned of several examples" of steam drum failure and replacement. However, NEPCO provides no further details, other than noting that in one instance, the drum failed during initial testing and was replaced. Replacement of a failed component at a new facility presumably would not increase emissions from the facility, and probably would be viewed as routine if the alternative was to forego operation of that new facility. Under such circumstances, it is unlikely that the replacement would trigger the Act's requirements.

The MEPCO's July 8, 1987 application to the PSC included a project cost estimate of \$83.9 million, of which \$45.6 million was designated as capital costs. A more recent cost estimate provided to EPA by MEPCO indicates that several work items are now deemed unnecessary, such that the cost of the original project is now estimated at \$70.5 million. However, all but \$89,000 of these reductions are designated as "maintenance" items. The recent submission also relates that the scope of the original project has now been expanded to include flue gas conditioning equipment and associated air heater work costing approximately \$17 million. Although MEPCO has not broken down these additional costs into capital and maintenance (or "expense") expenditures, it would appear that most, if not all, of this additional work would be classified as capital costs. Thus, it is highly likely that actual capital costs would be significantly higher than \$45.6 million.

-8-

It is important to note in this regard that MEPCO, at its option, could "net out" of PSD review by accepting federally enforceable restrictions on its potential to emit after the renovation. This could occur through enhancement of existing pollution control equipment, addition of new equipment, acceptance of federally enforceable operational restrictions, or some combination of these measures, limiting potential emissions to a level not significantly greater than representative actual emissions prior to the renovations. Theoretically, MEPCO could minimize the needed restrictions on its potential to emit following the renovations if it could show that some period other than the most recent two years is "more representative of normal source operation" [see 52.21(b)(21)(ii)]. (Obviously, such a showing would be most important with respect to unit 5, because it has been shut down and has had zero emissions since 1985.) Since these matters are within MEPCO's control, you should advise the company to enter discussions with Region V and Wisconsin, as appropriate, if MEPCO desires to "net out" of PSD review.

The MEPCO also argued in its July 29, 1988 letter, at payes 33-41, that even if EPA is correct that the Port Washington life extension project would involve physical changes within the meaning of the PSD regulations, any emissions increases would be due to increased production rates or hours of operation rather than higher emissions per unit of production. Therefore, WEPCO contends that these increases should be excluded from consideration in determining whether a net significant emissions increase and, hence, a major modification, would occur. The WEPCO is incorrect in this reyard.

As noted above, the exclusions cited by WEPCO are intended to apply where a source increases emissions by simply combusting a larger amount of fuel, or processing a larger amount of raw materials during a given time period, or by expanding its nours of operation "to take advantage of favorable market conditions" (see 45 FR 52704). In this instance, however, it is obvious that WEPCO's plans to increase production rate or hours of operation are inextricably intertwined with the physical changes planned under the life extension project. Absent the extensive renovations proposed at Port Washington, WEPCO would have little market incentive to, and in part would be physically unable to, increase operations at these aged and deteriorated facilities which, absent the renovations, would likely be retired from service in the near future. Thus, WEPCD's plans call for precisely the type of "Change in hours or rate or operation that would disturb a prior assessment of a source's environmental impact [and] should have to undergo [PSD review] scrutiny" (see 45 FR 52704). Conversely, accepting MEPCO's interpretation of the major modification regulations would serve to exclude from consideration all physical or operational changes except those which cause increased emissions per unit of production. Clearly, EPA never intended this result. It would allow, through substantial capital investment, significant expansion of the pollution-emitting capacity and longevity of major industrial facilities without PSD review of the impacts on air quality and opportunities for future economic growth.

The MEPCO contends (July 29, 1988 letter, at pages 20-27) that baseline capacity for the purpose of determining whether an increase in emission rate occurs for purposes of an MSPS modification is the original design capacity of the facility. This is incorrect. The thrust of the MSPS modification provisions is to compare actual maximum capacity before and after the change in question. Thus, original design capacity is irrelevant. The provision in 40 CFR 60.14(b)(2) for manual emission tests to determine whether an increase has occurred clearly contemplates that tests will be done just prior to and after the physical or operational change. The original design capacity of a unit, to the extent it differs from actual maximum capacity at the time of the test due to physical deterioration—and, hence, derating—of the facility, is immaterial to this calculation.

A. Physical or Operational Change

As with the Act's PSD provisions, a modification occurs for MSPS purposes, if there is either a physical or operational change [see 40 CFR 60.14(a)].

1. Physical Change

As is the case under the PSD provisions, the proposed renovations at Port Washington would constitute a physical change for NSPS purposes, at least at units 2, 3, 4, and 5. The WEPCO would need to supply more information, if EPA is to make a definitive determination as to unit 1.

The rear steam drums are part of the steam generating unit which constitutes the "affected facility" within the meaning of 40 CFR 60.41(a), and the drum replacements at units 2, 3, 4, and 5 are integral to the planned increase in maximum capacity, which is the purpose of the life extension project. With respect to unit 1, other physical changes would increase maximum capacity from 45 to 80 megawatts. However, there is some question whether those changes, in significant part, would occur at the steam generating unit or will be limited to the turbine/generator set, which is not part of the affected facility. We suggest that you pursue this matter with WEPCO to the extent necessary to determine MSPS applicability regarding unit 1.

As with PSD, the NSPS regulations exclude routine maintenance, repair, and replacement [see 60.14(e)(2)]. However, the renovations at the Port Washington steam generating units are not routine for MSPS purposes for the same reasons—detailed above—that they are not routine for PSD purposes.

2. Operational Change

Operational changes include both increases in hours of operation and increases in production rate. Section 60.14(e)(3) provides that an increase in hours of operation is not, by itself, a modification. However, an increase in production rate at an existing facility constitutes a modification, unless it can be accomplished without a capital expenditure on that facility [see 60.14(e)(2)].

increases, but trigger NSPS requirements only if the higher 50 percent level is reached. Thus, the suggestion made by WEPCO in its July 29, 1988 letter (at pages 14-15) that EPA must undertake rulemaking to amend the reconstruction regulations before NSPS could be applied to the Port Washington project is not well taken.

IV. Conclusion

In adopting the PSD and NSPS programs, Congress sought to focus air pollution control efforts at an efficient and logical point: the making of long-term decisions regarding the creation or renewal of major stationary sources. The Port Washington life extension project, as it has been presented to EPA, would involve a substantial financial investment at pollution-emitting facilities that may significantly increase potential emissions of air pollutants over a period well beyond the current life expectancy of those facilities. If the additional factual information called for in this memorandum shows that emissions increases would indeed result from this project, the project would be subject to PSD and MSPS requirements. Such a result would be in harmony with the broad policy objectives that Congress intended to achieve through these programs.

cc: Gerald Emison, OAQPS
Alan Eckert, OGC

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB)) Judge Bernard A. Friedman) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.)))
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)))
Defendants.))

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3

4.5

EPA APPLICATIONS OF THE ROUTINE MAINTENANCE EXCEPTION

EXHIBIT No.	DOCUMENT
3A	Regional Counsel Opinion, Request for Ruling Regarding Modification of Weyerhauser's Springfield Operations (Aug. 18, 1975)
3B	Letter from Robert B. Miller, EPA Region 5, to Steve Dunn, Wisc. Dep't Nat. Resources re: PSD applicability determination for project at P.H. Glatfelter Company facility (Jan. 12, 2003)
3C	Letter from Greg M. Worley, EPA Region 4, to Barry R. Stephens, Tenn. Dep't of Conservation re: proposed applicability determination for project at Packaging Corp. of America facility (Sept. 14, 2001)
3D	Letter from Richard R. Long, EPA Region 8, to Gary D. Helbling, N.D. Dep't of Health re: EPA Region 8's Opinion on Otter Tail Power Co. Coyote Station Low Pressure Rotor Upgrade Proposal (Apr. 17, 2001)
3E	In re Monroe Elec. Generating Plant Proposed Operating Permit, Petition No. 6-99-2 (June 11, 1999)
3F	Letter from David Howekamp, EPA Region 9, to Robert Connery, Holland & Hart re: Supplemental PSD Applicability Determination, Cyprus Casa Grande Corp. Copper Mining and Processing Facilities (Nov. 6, 1987)
3G	Letter from Robert Miller, EPA Region 5, to Don Smith, Minn. Pollution Control Agency re: PSD applicability determination for proposed project at Fairmont Utilities (Dec. 12. 1995)
3Н	Letter from Charles Whitmore, EPA Region 7, to Roger Randolph, Mo. Dept. of Natural Res. re: application of PSD or NSPS to proposed projects at Sibley Power Plant (Dec. 1, 1989)
31	Letter from R. Douglas Neeley, EPA Region 4, to Jimmy Johnston, Ga. Envtl. Protection Div. re: PSD applicability determination for project at PCA Pulp & Paper Mill (Sept. 13, 2000)
3J	Letter from Doug Cole, EPA Region 10, to Alan Newman, Wash. Dep't of Ecology re: PSD applicability determinations for projects at Longview Fibre & Boise Cascade Pulp & Paper Mills (Nov. 5, 2001)

3K	Letter from Lee Thomas, U.S. EPA, to John Boston, Wisconsin Electric Power Co. re: NSPS and PSD applicability determination for life extension project at Port Washington station (Oct. 14, 1988)
3L	Letter from Don Clay (U.S. EPA) to John Boston, Wisconsin Electric Power Co. re: revised NSPS and PSD applicability determination for life extension project at Port Washington station (Feb. 15, 1989)

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)
NATURAL RESOLUTIONS DEPENDE) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
Disinsiff Intervence)
Plaintiff-Intervenors)
V.)
DTE ENERGY COMPANY)
DTE ENERGY COMPANY, and)
DETROIT EDISON COMPANY)
)
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-A

REGIONAL COUNSEL OPINION DATED AUGUST 18, 1975

Request for Ruling Regarding Medification of Wayerincener's Springfield Operations

Request for rating regarding modification of Weyerhaesser's Springfield Operations.—Where Weyerhaesser proposes to medify its existing holiers in order to increase pressure of the steam, and medifications consist of installation of pressure parts to increase superheater surface, these installations constitute physical change which cannot be classified as routine maintenance, repair, or replaneases; changes constitute a modification for purposes of NSPS and PSD if changes will increase emissions (see: Clean Air Act Section 111(a)(4) and PSD regulations, Section 60.2(h)).—It is necessary to determine whether oil buller is considered feasil-fuel steam electric plant for purposes of PSD (in which case it will be exempt from PSD requirements), or whether it is to be considered integral part of a traft pulp mill (in which case it will be necessary to determine whether changes will increase emissions of sulfur dioxide or particulate spatter).

Pursuant to 40 CFR \$60.5, Weyerhaeuser Company has asked for an advanced determination of whether the installation of an electrical turbine generator and certain boiler modifications at its Springfield, Oregon, pulp mill will constitute a modification for purposes of the new source performance standards (NSPS) or the prevention of significant deterioration regulation (PSD).

At the present time, Weyerhaeuser has three boilers at its Springfield mill which produce steam for use in the pulping process. Two of the boilers are recovery boilers which utilize black liquor, a byproduct of the pulping process. The third is a conventional oil boiler. Weyerhaeuser intends to construct an electrical turbise generator to tap the energy contained in the steam before the susam is used in the pulping process. To do this, it will apparently be necessary for Weyerhaeuser to modify the existing hollers in order to increase the pressure of the steam. The modifications to the boilers will consist of the installation of pressure parts to increase the superheater surface. The company has indicated that the installation of additional pressure parts is within the original design capacity of the boilers. Weyerhaeuser also asserts that the emissions from these boilers will not be increased by the contemplated changes.

We have been asked by Ken Lepic to prepare a logal analysis of the following issue which is presented by Weyerhacuser's request.

QUESTION

Will the changes proposed by Weyerhaeuser for its Springfield mill constitute a modification for the purpose of NSPS or PSD?



REGIONAL COUNSEL OFFIGON DATED AUGUST 18, 1975

ANSWER

The installation of additional pressure parts in the three boilers constitutes a physical change which cannot be classified as routine maintenance, repair, or replacement. These changes will, therefore, be considered to be a modification for purposes of NSPS and PSD if the changes will result in increased emissions.

The changes in the two recovery boilers, however, will not be subject to the new source performance standards even if emissions from these boilers are increased since standards have not yet been proposed for kraft pulp mills. On the other hand, the oil boiler will have to comply with NSPS if its emissions are increased by the proposed modification since standards have been issued for fossil-fuel steam generators.

Weyerhacuser will not have to comply with the PSD regulations since the medifications probably will not increase emissions from the recovery boilers and since the oil boiler is too small to be covered.

DISCUSSION

Section 111(a)(4) of the Clean Air Act' defines the term "modification" for purposes of NSPS as including "any physical change in, or change in the method of operation of, a stationary source, which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." Any change which does not increase emissions is thus not a "modification" for purposes of Section 111.

The scope of the term "medification" is further limited by the definitions contained in the NSPS regulations and the PSD regulations. Section 60.2(h) provides:

"Modification" means any physical change in, or change in the method of operation of, an affected facility which increases the amount of any air pollutant (to which a standard applies) emitted by such facility or which results in the emission of any air pollutant (to which a standard applies) not proviously emitted, except that:

- (1) Routine maintenance, repair, and replacement shall not be considered physical changes, and
- (2) The following shall not be considered a change in the method of operation:
- (i) An increase in the production rate, if such increase does not exceed the operating design capacity of the affected facility:

'42 U.S.C. 1857c-6(a)(40).

REGIONAL COUNSEL OFINION DATED AUGUST 18, 1975

(ii) An increase in hours of operation;

(iii) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to such facility, as provided by \$60.1, the affected facility is designed to accommodate such alternative use. (Emphasis added).

The definition of "modification" in Section \$2.01(d) is identical except that an increase in the emission of any pollutant covered by a national ambient air quality standard is considered a modification for PSD.

Under this definition, any physical change which results in increased emissions must be considered a modification for purposes of both NSPS and PSD. Installation of additional pressure parts to increase the superhenter surface of the bollers would be considered by any court to constitute a physical change. Although the original design of the bollers may have contemplated the installation of additional pressure parts, such a physical change is well within the scope of the definitions found in §§52.01(d) and 60.2(h). In fact, it is irrelevant that the original boller design will parasit the installation of added pressure parts. The only exemption to the inclusion of all physical changes is that "[r]outine maintenance, repair, and replacement shall not be considered physical changes." Since the installation of additional pressure parts will increase the number of pressure parts contained in each boiler and will increase the total superheater surface of each boiler, these modifications cannot be considered to fall within the exemption for routine maintenance, repair, or replacement.

Weyerhaeuser has apparently tried to come within the exemption provided for an "increase in the production rate, if such increase does not exceed the operating design capacity of the source." This exemption, however, qualifies only the phrase "change in the method of operation." This exemption is not a limitation on the term "physical change." It is obvious, moreover, that the installation of pressure parts is a boiler is not an increase in the production rate or a change in the method of operation. It is rather a physical change in the boiler which may permit Weyerhaeuser to increase its production rate. The exemption for increased production rates is, for this reason, wholly inapply table.

It is still necessary to determine whether these changes will increase emissions covered by the applicable new source performance standards. Since standards have not yet been proposed for kraft pulp mills, the two recovery boilers will not have to comply with the requirements of Part 60. The oil boiler, however, will have to comply with the standards established for fossilfuel fired steam generators since these standards are expressly applicable to "each fossil-fuel fired steam generating unit of more than 63 million heal per

REGIONAL COUNSEL OPINION DATED AUGUST 18, 1975

hour heat input (250 million Btu per hour)"..." Weyerhacuser's oil boiler will operate at approximately 500 million Btu per hour."

With respect to the applicability of the PSD regulation, it will be necessary to determine whether or not emissions of a sulfur dioxide or particulate matter from the recovery boilers will be increased since the PSD regulation expressly covers kraft pulp mills. Although the PSD regulation does not indicate which facilities in kraft pulp mills are covered, it is clear that recovery boilers are covered by the PSD regulation in view of the fact that recovery furnaces were expressly covered in the proposed PSD regulation. On the other hand, it is possible to interpret the PSD regulation as either including or excluding the oil boiler from the kraft pulp mill category. We recommend, however, that the oil boiler be treated as a fossil-fuel fired steam electric plant for purposes of PSD to be consistent with its treatment under NSPS. If the oil boiler is considered a fossil-fuel steam electric plant for purposes of PSD, it will be exempt from the PSD requirements since the regulations cover only plants of more than 1,000 million Btu. If the oil boiler is considered an integral part of a kraft pulp mill, on the other hand, it will be necessary to determine whether the changes will increase emissions of sulfur dioxide or particulate matter.

⁴⁰ CFR \$60.40.

Letter from Heimut Wallenfelt to Kenneth A. Lepic, July 19, 1975, p. 2 of attachment.

⁴⁴⁰ CFR §52.21(d)(iii), 39 Fed. Reg. 42516 (December 5, 1974).

^{* 39} Fed. Reg. 31008 (August 27, 1974).

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)
) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE	
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
)
Plaintiff-Intervenors)
v.)
)
DTE ENERGY COMPANY, and)
DETROIT EDISON COMPANY	· ·
	·)
Defendants.	·)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-B

January 29, 2003

(AR-18J)

Steven Dumn
Wisconsin Department of Natural Resources
101 South Webster Street
P.O. Box 7921
Madison, Wisconsin 53707-7921

Dear Mr. Dunn:

This letter is in regards to your October 3, 2002, letter requesting assistance for a permit determination for P.H. Glatfelter Company. In your letter, you state that P.H. Glatfelter proposes to replace approximately 1060 steam tubes in one of its boilers with new steam tubes. The question you raised is whether the proposed project qualifies for the "routine maintenance, repair and replacement" PSD exemption under the definition of "major modification" as approved into the Wisconsin State Implementation Plan in Natural Resources (NR) chapter 405.02(21).

As you are aware, it is Wisconsin's responsibility, as the permitting authority, to determine whether P.H. Glatfelter's project is routine maintenance, repair or replacement. However, based on the information made available to us and as explained below, the United States Environmental Protection Agency's (USEPA) opinion is that the planned project should not be considered routine maintenance, repair or replacement under Wisconsin's regulations and USEPA guiding policies.

When assessing whether changes can be considered routine under the Clean Air Act's PSD regulations, we considered the nature, extent, purpose, frequency, cost, as well as other relevant factors. An example of this is provided in a letter from us dated May 23, 2000, concerning changes at a Detroit Edison power plant. This letter can be obtained from USEPA's NSR Internet database at http://www.epa.gov/ttn/nsr/gen/letterf3.pdf.

Our assessment of the proposed project is provided for your consideration as follows:

Nature and extent- The project will include replacing 1060 steam tubes in boiler number 1. This replacement differs from the more typical maintenance activities that are performed annually in that it involves a complete replacement of the tubes in a major component of the boiler, as opposed to replacement of just a few worn or damaged tubes on an as-needed basis. Additionally, the project is expected to require 5 weeks to complete.

C1N30B6RM0537

Replacement done on an as-needed basis has been stated to take no more than a day or two. The amount of time required for the project is significant compared to previous tube replacement project.

<u>Purpose</u>— It appears that the project may also serve to extend the useful life of the boiler. The boiler was built in 1968, a 34 year old boiler, and although the WDNR did not provide data on the average age of other similar boilers, the proposed project can be viewed as a significant repair of a major boiler component.

<u>Frequency</u>- As your letter indicates, this would be the first time in the 35 year life of the boiler where all the tubes would be replaced. Moreover, the infrequency of such replacement at this boiler supports our understanding that complete boiler tube replacements are not performed on a frequent basis.

<u>Cost</u>-According to your letter, this project is expected to cost \$450,000. In a follow-up discussion with the WDNR, it was stated that a typical tube repair cost would be approximately \$50,000. The project cost is significantly higher than the expected maintenance general replacement costs.

P.H. Glatfelter maintains that this project, when complete, will have no net effect on emissions or on the way the boiler is utilized in the existing operating mode, and as such, should not be subject to PSD review. Your letter does not provide sufficient information to make a determination of whether this project's change in emissions is greater than the PSD significance emissions threshold. However, as you are aware, a modification that results in a significant emissions increase comparing the unit's past actual to its future potential emissions, requires the modification to go through PSD review. The exception to this is the provision commonly known as the "WEPCO test", where past actual emission are compared to projected future emissions. It is our opinion, the unit in question is not an electric utility steam generating unit, and would therefore not be eligible for the WEPCO test.

In conclusion, with respect to this project's eligibility for an exemption from PSD pursuant to NR 405.02(21), we believe that this project does not represent routine maintenance, repair or replacement activities.

If you have any further questions, please feel free to contact me, or contact Constantine Blathras at (312) 886-0671.

Sincerely yours,

Robert B. Miller, Chief Permits and Grants Section

C1N30B6RM0538

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)
) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
)
Plaintiff-Intervenors)
v.)
)
DTE ENERGY COMPANY, and)
DETROIT EDISON COMPANY	
)
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-C

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

September 14, 2001

4APT-APB

Barry R. Stephens, P.E.
Tennessee Department of Environment and Conservation
Division of Air Pollution Control
9th Floor L&C Annex
401 Church Street
Nashville, Tennessee 37243-1531

Dear Mr. Stephens:

Thank you for the letter from the Tennessee Department of Environment and Conservation (TDEC) to the Region 4 office of the U.S. Environmental Protection Agency (EPA) dated July 17, 2001. In this letter, you requested EPA's views on a proposed determination made by TDEC concerning a pulp and paper mill in Counce, Tennessee. The proposed determination was that a planned project at the Packaging Corporation of America (PCA) pulp and paper mill could be considered routine maintenance, repair or replacement and therefore exempted from the prevention of significant deterioration (PSD) definition of major modification as allowed by the applicable PSD regulations in Tennessee Rule 1200-3-9-.01(4)(b)2.(i)(I).

It remains Tennessee's responsibility to determine whether PCA's project is routine maintenance, repair or replacement. However, based on the information made available to us and as more fully explained below, EPA's opinion is that the planned project should not be considered routine maintenance, repair or replacement under Tennessee regulations and EPA guiding policies.

Project Background

The PCA mill project in question focuses on Recovery Boiler #1 (R-1). The proposed project primarily consists of replacing all of the tubes in the R-1 generating bank. In addition, according to PCA's Executive Summary for the project's appropriation request, the project will also include replacement of 44 tubes on the center front side of the R-1 economizer. Based on information provided by PCA, relevant characteristics of the generating bank tubes and the entire boiler before and after the proposed project are as follows:



CIN30B6RM0494

	Before Project	After Project
Number of Generator Bank Tubes	1,273	1,173
Volume of Generator Bank Tubes (ft³)	519	477
Generator Bank Tubes as a Percentage of all R-1 Water Tubes (%)	20.4	19.0
Generator Bank Tube Wall Thickness (inches)	0.105	0.165
Steam Generating Capacity of Entire Boiler (lb/hr steam)	181,500	177,870
Permitted Maximum Black Liquor Solids Firing Rate (lb/hr)	114,000	114,000

The following additional background facts also were taken into account as part of our assessment:

- R-1 began operation in 1961, 40 years ago.
- So far as is known, the generator bank tubes were not replaced in their entirety until 1991 when an entire replacement was accomplished. In 1997, the generating bank left sidewall tubes were replaced, a project that we understand consisted of replacing 25 tubes. Complete tube replacement is required now because of "near drum thinning," a condition that can occur where the generator bank tubes join the generator bank mud drum. We further understand that PCA has determined tube replacement to be more practical than tube repair, in part because of the current close spacing of tubes at the point where corrosion has occurred.

Basis for Opinion

When assessing whether changes can be considered "routine" under PSD regulations, permitting authorities consider the following key factors: nature and extent, purpose, frequency, and cost. None of these factors on its own conclusively determines a project to be routine or not. Rather, the interrelationship of all factors should be examined together. As we have mentioned to you previously, an example of this procedure is provided in the letter from EPA Region 5 concerning changes at a Detroit Edison power plant.

For your consideration and based on the evaluation factors just listed, our assessment of the proposed R-1 generator bank and economizer tube replacement project is as follows:

Nature and Extent - As indicated above, the R-1 project will include replacing the
entirety of the existing 1,273 generating bank tubes with 1,173 new tubes. This
replacement differs from the more typical maintenance activities that are performed

annually in that it involves complete replacement of all the tubes in a major component of the boiler, as opposed to replacement of just a few worn or damaged tubes on an as-needed basis. In addition, the expected duration of the tube replacement project is approximately 20 days. Although the project is proposed for a period of scheduled mill outage, the amount of time required for the project is significant.

Using information provided by PCA, we compared the proposed project to other tube replacement and repair activities at the recovery boiler in question. From 1996 to 2000, PCA conducted various replacements of tubes on an annual basis, as well as some emergency repairs. None of the past tube replacement activities at the facility during this time period have been as extensive as the proposed project. Given the fact that the proposed project will consist of changing all of the generating bank tubes with an improved design that is intended to substantially increase the life of the tubes, the nature and extent of the project is not routine in nature and differs in scale from the less extensive and incremental maintenance projects more typical for this boiler.

- <u>Purpose</u> In different documents, PCA has explained the purpose of the proposed project as follows:
 - "The project is necessary to reduce risk of unplanned extended downtime due to failure in the generating bank or economizer." [from PCA's Executive Summary for the project's appropriation request]
 - The project will allow the boiler to operate safely and will have no effect on the firing rate capacity of the unit." [from PCA letter dated July 9, 2001]
 - "[T]he goal of this project is to allow continued safe operation of this boiler by replacing tubes which have become thin due to corrosion of the metal." [from PCA letter dated August 14, 2001]

Although EPA acknowledges the need to perform safety-related repairs to equipment, the fact that there are safety reasons for a project does not automatically render it routine maintenance, repair or replacement. Moreover, we are concerned that the project also serves as a life extension of the boiler. This concern is prompted by the age of the boiler (40 years) combined with the magnitude of the project (replacement of all tubes in a major component of the boiler) and the intent to install more widely spaced tubes with thicker walls that should promote a longer tube lifetime. Related to boiler age, PCA submitted a report from the National Council for Air and Stream Improvement (NCASI) containing information on the ages of recovery boilers used in the pulp and paper industry. (NCASI, June 1999, Estimated Costs for the U.S. Forest Products Industry to Meet the Greenhouse Gas Reduction Target in the Kyoto Protocol, Special Report No. 99-02.) According to this report, as of 1995 (six years

4

ago) the median age of recovery boilers then used in the U.S. pulp and paper industry was more than 25 years and about 15 percent of U.S. recovery boilers then in use (30 out of 192) were installed before 1960 (that is, were greater than or equal to 35 years in age at that time). We take from this that older recovery boilers are not unique to the PCA Counce mill, but that boilers of the age of R-1 are definitely in the minority. The proposed project therefore can be viewed as a significant repair of a major boiler component, and hence a project that will serve as a life extension of a recovery boiler that is older than the majority of existing recovery boilers in the industry. Life extension is an important factor in assessing whether the purpose of a project supports a conclusion that a project is routine or not.

- Frequency R-1 began service in 1961. Thirty years later, in 1991, the original generating bank tubes were replaced in their entirety due to near drum thinning. (The left sidewall tube replacement project in 1997 was much less extensive than the 1991 replacement project or the currently proposed project.) Therefore, during the entire 40-year operating history of R-1, a generating bank tube replacement project of the magnitude now proposed has occurred only once. Although we recognize that replacement of tubes other than generator bank tubes has occurred, our view is that an entire replacement of generating bank tubes is not a frequent occurrence. Consideration of the frequency factor, therefore, supports a conclusion that the proposed project is not routine.
- Cost The estimated cost of the proposed project is \$924,500. We understand this cost is in addition to normal R-1 annual maintenance costs that have ranged from \$629,968 to \$979,968 in the years 1997 through 2000 based on information supplied by PCA. Although we have taken note of PCA's estimate that the project cost is less than one percent of the cost of a new comparable recovery boiler, an added cost of nearly one million dollars is high enough to be within the range of costs for projects that have been considered non-routine by EPA in other contexts.

We believe that when all of the factors used to assess whether a project can be considered routine maintenance, repair or replacement are considered together, a finding that the proposed project is not routine should be made by the permitting authority.

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If you have any questions concerning this letter, please contact Jim Little at (404) 562-9118.

Sincerely,

Gregg M. Worley Chief Air Permits Section Air Planning Branch

cc: Richard Holland, PCA

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB)) Judge Bernard A. Friedman) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.	
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)))
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-D



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 8
999 18TH STREET - SUITE 300
DENVER, CO 80202-2466
http://www.epa.gov/region08

April 17, 2001

Ref: 8P-AR

Gary D. Helbling, Environmental Engineer ND Health Department Environmental Health Section P.O. Box 5520 Bismark, ND 58506-5520

Re:

EPA Region VIII's Opinion on Otter Tail Power Company's Coyote Station Low Pressure Rotor Upgrade Proposal

Dear Gary,

This is in response to your letter dated February 20, 2001, in which you requested EPA Region VIII's opinion on Otter Tail Power Company's (Otter Tail) Coyote Station prevention of significant deterioration (PSD) applicability determination.

It is my understanding that Otter Tail provided information on a proposed low pressure rotor upgrade at its Coyote Station Power Plant to you on November 20, 2000. In addition to the proposal, Otter Tail asked that the North Dakota Department of Health make a determination that the rotor upgrade not require review under the major new source review (NSR) permitting program on the ground that the "routine maintenance, repair, and replacement" exclusion applies to this project.

I also understand that you have already notified the company, in a letter dated March 29, 2001, that you consider the replacement to be routine. I believe that the North Dakota Department of Health may not have considered the appropriate criteria that should be applied to this analysis, specifically the criteria outlined in the May 23, 2000 letter to the Detroit Edison Company (Detroit Edison Letter). Given the Detroit Edison Letter, I disagree with your assertion in the letter to Otter Tail that EPA guidance is vague and unclear with respect to deciding what is "routine maintenance, repair, and replacement." See the discussion on pages 6 through 8, and the analysis discussed on pages 16 through 17 in the Detroit Edison Letter. I have attached this letter, which we shared with you previously, as Attachment B. Finally, I am concerned that Otter Tail could be liable for violations of the PSD requirements of the Clean Air Act should they commence construction without the appropriate permit.

C1N30B6RM0481



Please also find enclosed, as Attachment A, EPA Region VIII's opinion on Otter Tail's submittal regarding the proposed upgrades at Coyote Station. Please note that this is a preliminary interpretation of our requirements based on the information available to us at this time. I believe that Otter Tail will need to provide more information to substantiate its claim that their proposal qualifies for exemption from major modification as "routine maintenance, repair, and replacement."

The North Dakota Health Department is responsible for interpretation of its regulations and for making the appropriate decision of PSD applicability with regard to this source. If you have any further questions or concerns regarding this matter, please contact Kathleen Paser at 303-312-6526.

Sincerely,

Richard R. Long, Director Air and Radiation Program

RRL/KSP

cc: Tom Bachman, ND Department of Health Karen Blanchard, OAQPS Dan DeRoek, OAQPS Carol Holmes, OECA Anna Wood, OGC Scott Whitmore, EPA Region 8, 8ENF-T Ron Rutherford, EPA Region 8, 8ENF-T

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors))
٧.)
DTE ENERGY COMPANY, and	,)
DETROIT EDISON COMPANY)
~)
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-E

BEFORE THE ADMINISTRATOR UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF)
MONROE ELECTRIC GENERATING)
PLANT)
ENTERGY LOUISIANA, INC.)
PROPOSED OPERATING PERMIT)
Proposed by the Louisiana)
Department of Environmental)
Quality)

PETITION NO. 6-99-2 ORDER RESPONDING TO PETITIONER'S REQUEST THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF A STATE OPERATING PERMIT

ORDER PARTIALLY GRANTING AND PARTIALLY DENYING PETITION FOR OBJECTION TO PERMIT

On February 9, 1999, Ms. Merrijane Yerger, Managing Director of the Citizens for Clean Air & Water ("CCAW" or "Petitioner"), petitioned the Environmental Protection Agency ("EPA"), pursuant to section 505(b) of the Clean Air Act ("CAA" or "the Act"), to object to issuance of a proposed State operating permit to Entergy Louisiana, Inc.'s Monroe Electric Generating Plant in Monroe, Louisiana ("Monroe plant"). The proposed operating permit for the Monroe plant was proposed for issuance by the Louisiana Department of Environmental Quality ("LDEQ") pursuant to title V of the Act, CAA §§ 501 - 507, the federal implementing regulations, 40 CFR Part 70, and the State of Louisiana regulations, Louisiana Administrative Code ("L.A.C."), Title 33, Part III, Chapter 5, sections 507 et seq.

Petitioner has requested that EPA review, investigate, and make an administrative determination on the entire matter of the proposed operating permit and planned restart of the Monroe plant, pursuant to section 505(b) of the Act and 40 CFR 5 70.8(c). Petitioner alleges that the proposed operating permit is not in compliance with applicable requirements of the Act including Prevention of Significant Deterioration ("PSD") permitting requirements and New Source Performance Standards ("NSPS"). Petitioner also alleges that Entergy's operating permit application fails to adequately demonstrate compliance with hazardous waste disposal requirements under the Resource Conservation and Recovery Act ("RCRA").

For the reasons set forth below, I find that the proposed title V permit does not assure compliance with applicable PSD requirements as set forth in the Louisiana State Implementation Plan ("SIP"). I therefore grant the Petitioner's request in part and object to issuance of the proposed title V permit unless the permit is revised in accordance with this Order. I deny the Petitioner's remaining claims.

I. STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act calls upon each State to develop and submit to EPA an operating permit program to meet the requirements of title V. The State of Louisiana submitted a title V program governing the issuance of operating permits on November 15, 1993, and subsequently revised this program on November 10, 1994. 40 CFR Part 70, Appendix A. In September of 1995, EPA granted full approval of the Louisiana title V operating permits program, which became effective on October 12, 1995. 60 Fed. Reg. 47296 (Sept. 12, 1995); 40 CFR Part 70, Appendix A. This program is codified in L.A.C. Title 33, Part III, Chapter 5, sections 507 et seq. Major stationary sources of air pollution and other sources covered by title V are required to obtain an operating permit that includes emission limitations and such other conditions as are necessary to assure compliance with applicable requirements of the Act. See CAA §§ 502(a) and 504(a).

The title V operating permits program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units in a single document and that compliance with these applicable requirements is assured. See Order In re Roosevelt Regional Landfill, at 2 (May 4, 1999). Such applicable requirements include the requirement to obtain preconstruction permits that comply with applicable new source review requirements. Id. at 8.1

Louisiana defines "federally applicable requirement" in relevant part to include "any standard or other requirement provided for in the Louisiana State Implementation Plan ("SIP") approved or promulgated by EPA through rulemaking under title I of the Clean Air Act that implements the relevant requirements of the Clean Air Act, including any revisions to that plan

Under section 505(b) of the Act and 40 CFR § 70.8(c), states are required to submit all operating permits proposed pursuant to title V to EPA for review and EPA will object to permits determined by the Agency not to be in compliance with applicable requirements or the requirements of 40 CFR Part 70. If EPA does not object to a permit on its own initiative, section 505(b)(2) of the Act and 40 CFR § 70.8(d) provide that any person may petition the Administrator, within 60 days of the expiration of EPA's 45-day review period, to object to the permit.

To justify exercise of an objection by EPA to a title V permit pursuant to section 505(b)(2), a petitioner must demonstrate that the permit is not in compliance with the requirements of the Act, including the requirements of Part 70. Petitions must, in general, be based on objections to the permit that were raised with reasonable specificity during the public comment period. A petition for review does not stay the effectiveness of the permit or its requirements if the permit was issued after the expiration of EPA's 45-day review period and before receipt of the objection. If EPA objects to a permit in response to a petition and the permit has not been issued, the permitting authority shall not issue the permit until EPA's objection has been resolved. 40 CFR § 70.8(d).

II. BACKGROUND

The Monroe plant, located in Monroe, Louisiana, currently consists of three units (Units 10, 11 and 12), each with a boiler and ancillary equipment, which were installed in 1961, 1963, and

promulgated in 40 CFR part 52, subpart T." L.A.C. 33:III.502. EPA approved a PSD program in the State of Louisiana's SIP on April 24, 1987. 52 Fed. Reg. 13671; 40 CFR § 52.986. Thus, the applicable requirements of the Act respecting the Monroe plant permit include the requirement to comply with the applicable PSD requirements under the Louisiana SIP.

² The Monroe area is currently designated as attainment for all National Ambient Air Quality Standards ("NAAQS") established by EPA.

1968, respectively. Each boiler is fired primarily with natural gas, but is also capable of being fired with diesel fuel oil. The rated capacities of the units are 23 megawatts ("MW"), 41 MW, and 74 MW, respectively. The total heat input for the units is .1,961 million British thermal units ("MMBtu"). Installation of these boilers was not subject to PSD review because it predated the PSD program.

On July 1, 1988, Louisiana Power & Light ("LP&L"), predecessor to Entergy Louisiana, Inc. ("Entergy"), placed the plant's three units in extended reserve shutdown ("ERS").

The record further reflects that the units were not in regular operation for several years prior to placing the units in extended reserve shutdown. See Letter from Entergy to Jayne Fontenot, Chief, Permits Issuance Section, EPA, Region VI (July 18, 1994) (noting that Monroe plant has not operated on a routine basis since 1981). Internal LDEQ memoranda further suggest that the Monroe plant ceased operating around January 1988. See Memo from Paul Laird, LDEQ Northeast Regional Office, to John R.

³ The City of Monroe built the plant in approximately 1895, and owned and operated the plant until 1978, when Louisiana Power & Light became the operator and subsequently the owner of the plant. Louisiana Power & Light changed its name to Entergy Louisiana, Inc. in 1996.

Units 10, 11 and 12 are the most recent additions Units 1 through 9 at the Monroe plant have been permanently decommissioned. The last of these, Unit 9, was permanently retired effective December 31, 1987. See Memo from D.L. Aswell, LP&L, to William Phillips, SSI (Dec. 18, 1987). This memo and other documents referred to in this Order are on file with EPA.

[•] The proposed title V permit would allow up to 15 percent of the facility's fuel use to be diesel fuel oil.

Memo from E.M. Ormond, LP&L, to Glenn F. Phillips (June 28, 1988). Extended reserve shutdown is a program implemented by the Entergy Operating Companies (of which Entergy Louisiana is a member) in the mid-1980's to save money by placing units in inactive status and reducing operating staff, maintenance costs, and deferring the cost of repairing units. See Louisiana Public Service Commission, Order No. U-20925-G at 8-9 (Nov. 18, 1998).

2:10-cv-13101-BAF-RSW Doc#117-9 Filed 07/18/11 Pg 6 of 31 Pg ID 5282 According to Entergy, these units were placed in extended reserve shutdown because of the addition of new electric generating capacity in the area. Memo from Entergy to EPA, "Actions Taken By Entergy At Monroe Generating Station." At the time of shutdown, LP&L projected that Units 10, 11 and 12 would not be needed for three to five years. Id. That period grew to eleven years as a result of "many factors," according to Entergy, including increased competition and demand-side management. Id.

Some time around September, 1988, LP&L initiated a number of activities at the Monroe plant to prepare the plant for extended shutdown, including draining, disconnecting and covering equipment, and installing and operating dehumidification equipment to prevent corrosion of the units. During shutdown, LP&L/Entergy conducted some inspection and maintenance activities, primarily in response to problems with the dehumidification system. During this period, LP&L/Entergy also maintained relevant environmental permits for the Monroe plant; including payment of air quality maintenance fees to LDEQ (between \$1,100 and \$1,300 per year), maintenance of water permits, and applications for an acid rain permit (received October 23, 1996) and a title V operating permit.

Entergy now proposes to restart Units 10, 11 and 12 at the Monroe plant beginning this summer. On September 16, 1996, Entergy submitted a title V permit application to LDEQ. The total estimated annual emissions of air pollutants associated with the plant, in tons per year ("tpy"), are as follows: nitrogen oxides ("NOx"), 4,972.65 tpy; sulfur dioxide ("SO2"), 679.84 tpy; carbon monoxide ("CO"), 361.65 tpy; particulate matter ("PM10"), 32.46 tpy; and volatile organic compounds ("VOCs"), 12.74 tpy. These projected annual emission rates are incorporated as annual emission limits in the proposed title V permit. The requested operating permit includes no limitations

Newton, LDEQ, Air Quality Div. (Feb. 8, 1989); Memo from Paul Laird, LDEQ Northeast Regional Office, to John R. Newton, LDEQ, Air Quality Div. (Feb. 24, 1988).

⁶ Other activities included stack inspections in 1992, installation of an oil/water separator for the stormwater system in 1996, and cleaning of the diesel fuel oil tank system in 1996.

on the hours of operation or the capacities at which the units would operate. Most relevant for purposes of this Order, neither the permit application nor the proposed permit provides for obtaining a PSD permit for the units prior to restart, under the Louisiana PSD program.

LDEQ submitted a proposed title V permit to EPA Region VI for review on November 16, 1998. The permit went out for public comment on November 25, 1998. Public commenters requested a public hearing. Notice of a public hearing was published on January 16, 1999. A public hearing was held by LDEQ on February 18, 1999. The public comment period ended April 20, 1999. EPA's 45-day review period expired on December 31, 1998. On February 9, 1999, Citizens for Clean Air & Water filed a timely petition with EPA pursuant to section 505(b)(2) of the Clean Air Act requesting that EPA object to issuance of the proposed permit for the Entergy Monroe plant. As of this date, no final permit has been issued.

III. ISSUES RAISED BY PETITIONER

Petitioner objects to issuance of the proposed permit on five grounds: (1) LDEQ failed to subject the Monroe plant to PSD review; (2) the maximum capacity of the Monroe plant may have been increased by some unknown method at some time between 1976 and the time of the title V application without being subject to PSD review or NSPS; (3) the proposed permit fails to incorporate enforceable one-hour maximum emission rate limitations for sulfur dioxide and other criteria pollutants; (4) the proposed permit includes apparent annual emissions increases that suggest PSD review should be conducted for the sulfur dioxide emissions; and (5) sufficient information has not been provided in Entergy's permit application to ensure compliance with RCRA disposal requirements.⁷

⁷ These objections were also raised during the public hearing and in correspondence to LDEQ and Region VI from Mr. Alexander J. Sagady, Environmental Consultant, on behalf of CCAW, dated February 18, 1999. Accordingly, Petitioner has met her obligation to base the petition on objections to the permit raised with reasonable specificity during the public comment period.

In addition, the Petitioner requests the following: (1) that EPA issue an information request letter to Entergy and the City of Monroe under section 114 of the Act, requiring them to disclose all matters raised by this petition; and (2) that EPA conduct an on-site inspection of the Monroe plant to determine whether PSD and NSPS have been triggered.

Items (1), (3) and (4) are either addressed in the PSD applicability analysis or rendered moot by EPA's conclusion that the proposed title V permit must be revised to ensure compliance with applicable PSD requirements. Section V addresses Item (2); Section VI addresses Item (5). In response to Petitioner's request for an inspection, on May 17, 1999, EPA conducted an inspection of the Monroe plant to verify the activities being conducted at the plant and to confirm that the plant is not operating. Finally, in response to Petitioner's request that EPA issue an information request letter, EPA believes it has sufficient information to respond to the Petition and that there is no need at this time for such a letter.

IV. PSD APPLICABILITY ANALYSIS

The following sections describe EPA's analytical tests for determining PSD applicability and apply these tests to the proposed restart of the Monroe plant. EPA concludes that the proposed restart of the Monroe plant should be subject to PSD requirements and thus, that the title V permit does not assure compliance with the applicable PSD requirements set forth in the Louisiana SIP. The analysis in this Order, however, does not purport to dictate the specific PSD permit terms that the State should adopt in revising the title V permit.

A. Analytical Approach

Part C of title I of the Clean Air Act establishes the statutory framework for protecting public health and welfare from adverse effects of air pollution, notwithstanding attainment and maintenance of all NAAQS. Congress specified that the PSD program is intended to:

(1) "insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources"; and

(2) "assure that any decision to permit increased air pollution . . . is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process."

CAA § 160.

To accomplish these purposes, the Act relies primarily on a permitting program as the mechanism for reviewing proposals to increase air pollution in areas meeting the NAAQS. The Act generally requires PSD permits prior to construction and/or operation of new major stationary sources and major modifications to stationary sources in areas designated attainment or unclassified for the pollutants to be emitted by the sources.

See CAA §§ 165(a) and 169(2)(C). "Modification" is defined to include, "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." CAA § 111(a)(4). By regulation, EPA has limited the facially broad sweep of the PSD provisions to only "major" modifications. 40 CFR § 51.156(i); see also L.A.C. 33:III.509(I).

As described in the following sections, reactivation of facilities that have been in an extended condition of inoperation may trigger PSD requirements as "construction" of either a new major stationary source or a major modification of an existing stationary source. Where facilities are reactivated after having been permanently shutdown, operation of the facility will be treated as operation of a new source. Alternatively, shutdown and subsequent reactivation of a long-dormant facility may trigger PSD review by qualifying as a major modification. This section describes EPA's approach for analyzing whether restart of a facility triggers PSD review as: (1) a new major source under EPA's Reactivation Policy; (2) a major modification by virtue of a physical change resulting in a significant net emissions increase; or (3) a major modification by virtue of a change in the method of operation resulting in a significant net increase

2:10-cv-13101-BAF-RSW Doc#117-9 Filed 07/18/11 Pg 10 of 31 Pg ID 5286 in emissions.

 Restart Treated as New Source -- EPA's Reactivation Policy

EPA has a well-established policy that reactivation of a permanently shutdown facility will be treated as operation of a new source for purposes of PSD review. The key determination to be made under this policy is whether the facility to be reactivated was "permanently shutdown." In general, EPA has explained that whether or not a shutdown should be treated as permanent depends on the intention of the owner or operator at the time of shutdown based on all facts and circumstances. Shutdowns of more than two years, or that have resulted in the removal of the source from the State's emissions inventory, are presumed to be permanent. In such cases it is up to the facility owner or operator to rebut the presumption.

To determine the intent of the owner or operator, EPA has

⁸ Whether a source is subject to preconstruction review as a new source or as a major modification may be significant in particular cases for determining the appropriate analysis of control technology options and other PSD requirements. For example, analysis of control technology for major modifications might consider the age or configuration of the source where review for new sources might not. Likewise, analysis of alternatives for new sources might consider alternative locations where the same analysis for major modifications might not.

^{&#}x27;See Memo from Edward E. Reich, Director, Div. of
Stationary Source Enforcement, to Stephen A. Dvorkin, Chief,
General Enforcement Branch, Region II (Sept. 6, 1978); Memo from
Edward E. Reich, Director, Stationary Source Enforcement Div., to
William K. Sawyer, General Enforcement Branch, Region II (Aug. 8,
1980); Memo from John S. Seitz, Director, Stationary Source
Compliance Div., OAQPS, to David P. Howekamp, Director, Air Mgt.
Div., Region IX (May 27, 1987); Letter from David P. Howekamp,
Director, Air Mgt. Div., Region IX, to Robert T. Connery, Holland
& Hart (Nov. 6, 1987); Memo from John B. Rasnic, Director,
Stationary Source Compliance Div., OAQPS, to Douglas M. Skie,
Director, Air Programs Branch (Nov. 9, 1991).

examined factors such as the amount of time the facility has been out of operation, the reason for the shutdown, statements by the owner or operator regarding intent, cost and time required to reactivate the facility, status of permits, and ongoing maintenance and inspections that have been conducted during shutdown. No single factor is likely to be conclusive in the Agency's assessment of these factors, and the final determination will often involve a judgment as to whether the owner's or operator's actions at the facility during shutdown support or refute any express statements regarding the owner's or operator's intentions.¹⁰

While the policy suggests that the key determination is whether, at the time of shutdown, the owner or operator intended shutdown to be permanent, in practice, after two years, statements of original intent are not considered determinative. Instead, EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen. To make this assessment, EPA looks at activities during time of shutdown that evidence the continuing validity of the original intent not to permanently shut down.

Thus, to preserve their ability to reopen without a new source permit, EPA believes owners and operators of shutdown facilities must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. If they cannot make such a demonstration, it suggests

Compliance Div., OAQPS, to David P. Howekamp, Director, Air Mgt. Div., Region IX (May 27, 1987) (finding shutdown of Noranda Lakeshore Mines' roaster leach plant to be permanent despite express statements from the facility owners that shutdown was temporary, and evidence that the plant was maintained during shutdown); but cf. Memo from John B. Rasnic, Director, Stationary Source Compliance Div., OAQPS, to Douglas M. Skie, Chief, Air Programs Branch (Nov. 19, 1991) (finding reactivation of Watertown Power Plant did not trigger PSD based on the fact that the statements of intent by the owners were supported by documentation regarding maintenance of the facility during shutdown and, as a result, the ability to reactivate the plant easily).

that for at least some period of the shutdown, the shutdown was intended to be permanent. Once it is found that an owner or operator has no real plan to restart a particular facility, such owner or operator cannot overcome this suggestion that the shutdown was intended to be permanent by later pointing to the most recent efforts to reopen the facility.

2. Restart as a Major Modification -- Physical Change

In addition to possibly triggering PSD requirements as a new source, restart of an idle facility may also trigger PSD review if it meets the definition of a major modification. EPA's PSD regulations define "major modification" as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act." 40 CFR § 51.166(b)(2)(i); see also L.A.C. 33:III.509(B).12

"Physical change" is not defined in the Clean Air Act or in EPA's PSD regulations. Instead, EPA's regulations describe those activities that are <u>not</u> considered physical changes; most notably, the regulations exclude routine maintenance, repair and

This approach for assessing the intent of the owner or operator is consistent with the general notion that a company cannot sit indefinitely on a governmental permission to emit air pollution without showing some definite intention to use it. See 40 CFR § 52.21(r) (construction must be commenced within 18 months of receiving a permit); L.A.C. 33:III.509(R); see also In re West Suburban Recycling and Energy Center, L.P., PSD Appeal No. 97-12, slip op. at 8 (EAB, Mar. 10, 1999) (finding PSD permit should be denied because "there is no realistic prospect that the resource recovery facility described in WSREC's permit application will be completed").

Net emissions increases are calculated by combining any increase in actual emissions from a particular physical change or change in the method of operations, with any increase or decrease in actual emissions at the source that are contemporaneous with the particular change and otherwise creditable. 40 CFR § 51.166(b)(3); see also L.A.C. 33:III.509(B). See infra at V.A.4.

replacement. Outside these exceptions, the Agency and courts have interpreted "physical change" broadly. See, e.g., Wisconsin Elec. Power Co. v. Reilly ("WEPCO"), 893 F.2d 901, 908 (7th Cir. 1990) (noting that "courts considering the modification provisions of NSPS and PSD have assumed that 'any physical change' means precisely that").

As a result of this broad statutory definition, most analysis of whether PSD review is triggered under this provision will focus on whether the activities at the facility fit within one of the regulatory exceptions, in particular the routine maintenance, repair and replacement exception provided in 40 CFR § 50.21(b)(2)(iii)(a). To distinguish between physical changes and work that is routine, "EPA makes case-by-case determinations by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding." WEPCO, 893 F.2d at 910 (quoting Memo from Don R. Clay, Acting Assistant Admin. for Air and Radiation, to David A. Kee, Director, Air and Radiation Div., Region V (Sept. 9, 1988)); see also Letter from David P. Howekamp, Director, Air Mgt. Div., Region IX, to Robert T. Connery, Holland & Hart ("Cyprus Casa Grande Letter") (Nov. 6, 1987) (concluding work conducted at facility was not routine "when viewed as a whole").

3. Restart as a Major Modification -- Change in the Method of Operation

Restart of a long-dormant facility may also be treated as a major modification subject to PSD review if it represents a "change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act." 40 CFR § 51.166(b)(2)(i); see also L.A.C. 33:III.509(B). As with the term "physical change," the regulations do not define the meaning of "change in the method of operation" except by listing those activities that do not constitute such changes. 40 CFR § 51.166(b)(2)(iii); see also L.A.C. 33:III.509(B). The most relevant exception for analyzing whether restart of a shutdown facility might be treated as a change in the method of operation is 40 CFR § 51.166(b)(2)(iii)(f); see also L.A.C. 33:III.509(B). This provision exempts from PSD review "[a]n increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit

condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166." 40 CFR § 51.166(b)(2)(iii)(f); see also L.A.C. 33:III.509(B).

The purpose of this "increase in hours" exception was to avoid undue disruption by allowing routine increases in production during the normal course of business in order to respond to market conditions. In the preamble to the PSD rulemaking, EPA explained:

While EPA has concluded that as a general rule Congress intended any significant net increase in such emissions to undergo PSD or nonattainment review, it is also convinced that Congress could not have intended a company to have to get an NSR permit before it could lawfully change hours or rate of operation. Plainly, such a requirement would severely and unduly hamper the ability of any company to take advantage of favorable market conditions.

45 Fed. Reg. 52676, 52704 (Aug. 7, 1980). The court in WEPCO explained further, "This exclusion . . . was provided to allow facilities to take advantage of fluctuating market conditions, not construction or modification." 893 F.2d at 916 n.11.

Analysis of whether restart of a facility constitutes a mere increase in the hours of operation or production rate must consider whether the proposed activity is of the kind intended to be covered by the provision. Specifically, EPA will look at whether the proposed change requires enhanced flexibility to avoid hampering a company's ability to respond to market fluctuations. In general, reactivation after long periods of shutdown, though obviously motivated by long-term changes in the market, is not a response to the same type of market fluctuations and does not merit the same permitting flexibility envisioned by the regulations.

Restart of a long-dormant facility also may not be entitled to coverage under the "increase in hours" exemption if it would disturb a prior assessment of the environmental impact of the source. In the preamble for the 1980 PSD rulemaking, after expressing its belief that Congress intended to allow certain facilities flexibility to respond to market fluctuations, EPA

explained, "At the same time any change in hours or rate of operation that would disturb a prior assessment of a source's environmental impact should have to undergo scrutiny." 45 Fed. Reg. 52676, 52704 (Aug. 7, 1980). As a result, EPA will not exempt increases in the hours of operation in situations where the increase in hours would be prohibited by a permit condition or where the increase would "interfere with a state's efforts in air quality planning . . . " Letter from David P. Howekamp, Director, Air Mgt. Div., Region IX, to Robert T. Connery, Holland & Hart (Nov. 6, 1987).

In the Cyprus Casa Grande PSD applicability determination, EPA concluded that restart of a roaster/leach/acid ("RLA") plant after 10 years of shutdown constituted a change in the method of operation. EPA distinguished restart of the plant from a mere increase in the hours of operation, explaining that the exemption was not intended to cover restart of facilities after long periods of shutdown. The letter explained:

EPA's original intention to disallow the [increase in hours] exclusion where it would "disturb a prior assessment of a source's environmental impact" leads me to conclude that the exclusion should not be applied here. This is so because our present assessment as well as that of the State of Arizona, is that the RLA plant in its current non-operating condition has no environmental impact. This is evidenced in part by the removal of the plant from the state's emission inventory and the surrender of operating permits. An additional factor is the simple physical fact that the RLA plant has had zero emissions for ten years.

Letter from David P. Howekamp, Director, Air Mgt. Div., Region IX, to Robert T. Connery, Holland & Hart (Nov. 6, 1987).

4. Restart as a Major Modification -- Emissions Netting Baseline

Once restart is found to be involve either a physical change or a change in the method of operation, the Agency must determine if the change results in a significant net emissions increase of a pollutant subject to regulation under the Act. 40 CFR § 51.166(b)(2)(i); see also L.A.C. 33:III.509(B). The first step in calculating the net emissions increase is to determine whether

the particular physical or operational change in question would itself result in a significant increase in "actual emissions." See 40 CFR § 51.166(b)(3)(i)(a) and (b)(21); see also L.A.C. 33:III.509(B). If so, the second step is to identify and quantify any other prior increases and decreases in "actual emissions" that would be "contemporaneous" with the particular change and otherwise creditable. See 40 CFR § 51.166(b)(3)(i)(b); L.A.C. 33:III.509(B). The third step is to total the increase from the particular change with the other contemporaneous increases and decreases. See 40 CFR § 51.166(b)(3)(i)(b); L.A.C. 33:III.509(B). If the total would exceed zero, then a "net emissions increase" would result from the change. Whether this net emissions increase of a regulated pollutant is "significant" is determined in accordance with the annual tonnage thresholds set forth in 40 CFR § 51.166(b)(23) and L.A.C. 33:III.509(B).

The primary issue in calculating the net emissions increase associated with the restart of a shutdown facility is usually calculation of the actual emissions increase. To calculate the actual emissions increase associated with the change, the emissions from the source after the change is made must be compared to the "baseline emissions" of the source, which are the actual emissions of the source as of a "particular date" (i.e., immediately prior to the physical or operational change in question). The regulations provide, "In general, actual emission as of a particular date shall equal the average rate . . . at which the unit actually emitted the pollutant during a two-year period which precedes the particular date (the date of the change) and which is representative of normal source operations." 40 CFR § 51.166(b) (21) (ii); see also L.A.C. 33:III.509(B).

The regulations give EPA (or the permitting authority) discretion to set a different period for determining baseline emissions if such a period is more representative of normal source operations. 40 CFR § 51.166(b)(21)(ii); see also L.A.C. 33:III.509(B). EPA, however, has applied its discretion narrowly in assigning representative periods other than the two years immediately preceding the physical or operational change. One exception was provided in the preamble to the 1992 "WEPCO rulemaking." 57 Fed. Reg. 32314, 32325 (July 21, 1992). There EPA said that for utilities it would consider as "representative," actual emission levels from any two years

within the five years preceding the physical or operational change. In that same preamble, however, EPA specifically rejected one commenter's argument that EPA should consider a two-year period within the last five years of a plant's operation as the representative period for plants that have been shut down for more than five years. See 57 Fed. Reg. 32314, 32325 (July 21, 1992).

On more than one occasion, EPA has made clear that in calculating the net emissions increase for reactivation of long-dormant sources potentially subject to PSD, the source is considered to have zero emissions as its baseline. In both the Cyprus Casa Grande applicability determination and the Cyprus Minnesota applicability determination, EPA set the baseline emissions level at zero for facilities that had been shut down or idle for 10 years. See Letter from David P. Howekamp, Director, Air Mgt. Div., Region IX, to Robert T. Connery, Holland & Hart (Nov. 6, 1987); Memo from John Calcagni, Director, Air Quality Mgt. Div., to David Kee, Director, Air and Radiation Div., Region V ("Cyprus Minnesota") (Aug. 11, 1992). In the Cyprus Minnesota applicability determination, after noting EPA's policy announcement in the WEPCO rulemaking, EPA explained that it has limited flexibility to adjust the "representative period."

For many reactivations of long-shutdown facilities that fall within the definition of a physical or operational change, the only step in calculating "significant net emissions increase" will be a determination of whether the increase in emissions resulting from the change is significant under 40 CFR § 51.166(b)(23)¹⁴ because the baseline for actual emissions will be zero, and there will be no other emissions increases or

¹³ <u>See also Memo from John Calcagni, Director, EPA Air</u> Quality Management Div., to David Kee, Director, Air and Radiation Div., EPA Region V (Aug. 11, 1992) (noting that representative period other than previous two years generally limited to catastrophic occurrences); EPA, <u>Draft New Source</u> Review workshop Manual at A.39 (Oct. 1990).

¹⁴ For Louisiana, the thresholds are provided at L.A.C. 33:III.509(B) in the definition of "significant" and are the same as the federal thresholds relevant here.

decreases that are contemporaneous with the change.15

Since 1992, EPA regulations have allowed states to adopt a somewhat different approach to determining emissions increases for electric utility steam generating units. See 40 CFR § 51.166(b)(21)(iv), (v). Such units' post-change emissions may be established by a source estimating the future emissions of the unit and submitting to the state information to confirm the accuracy of those estimates. See 40 CFR §§ 51.166(b)(21)(v), (b)(32). However, states and localities are not required to include these special provisions for electric utility steam generating units in their PSD programs. See 40 CFR § 51.166(b) (allowing variations from federal rules when local rules are more stringent). Louisiana has not adopted the special provisions; accordingly, Entergy's post-change emissions will in this case be determined by its potential to emit, rather than by its

¹⁵ As discussed above, the PSD regulations provide that the increase in emissions is determined by subtracting the affected units' pre-change "actual emissions" (referred to above as the "baseline") from their post-change "actual emissions." For units that have not "begun normal operations," the regulations generally provide that actual emissions are equal to the units' "potential to emit." 40 CFR § 51.166(b)(21)(iv). EPA interprets this provision to mean that units which have undertaken a nonroutine physical or operational change have not "begun normal operations" within the meaning of the PSD regulations, since prechange emissions may not be indicative of how the units will be operated following the non-routine change. See 57 Fed. Reg. 32314, 32326 (amending rules only for certain modifications at electric utility steam generating units and reserving "begun normal operations" language for other modifications); 63 Fed. Reg. 39857, 39859 n.4 (July 24, 1998) (post-change emissions of unit following non-routine change is potential to emit). practice, this provision merely establishes a regulatory presumption that the units will operate at their maximum design capacity following the change. Sources can and frequently do rebut this presumption and avoid PSD applicability. They do so by agreeing to add pollution controls and/or accepting operational restrictions in a "minor NSR" permit or similar instrument that limits their emissions following the change to levels that are not significantly greater than pre-change actual emissions. See 40 CFR § 51.166(b)(4).

B. Applicability of PSD to Restart of Monroe Plant

1. PSD Applicability Under EPA's Reactivation Policy

Entergy is proposing to restart three units at its Monroe plant that have been placed in "extended reserve shutdown" since July 1, 1988. At the outset, under EPA's Reactivation Policy, because these units have been shut down for more than two years, shutdown of these units is presumed to be permanent. Unless Entergy provides adequate support to rebut this presumption, restart of these units will be treated as activation of a new source subject to PSD. The remainder of this section discusses whether Entergy has adequately demonstrated that the units were never intended to be permanently shut down. 16

Before formally placing the Monroe plant into extended reserve shutdown, then-owner LP&L prepared an Extended Reserve Shutdown Plan dated October 27, 1987, which described plans to maintain the plant in a reserved status to be available when the demand for electricity increased. This plan included the installation of dehumidification systems, which were subsequently installed, to preserve the electric generation units. At the

projections of future emissions. In this case, however, even if Louisiana had adopted the special provisions for utilities, it would not change the outcome. This is so because Entergy has projected, and its proposed title V permit reflects, that it will operate at its full, unrestricted maximum capacity of 8760 hours per year. See Proposed Operating Permit, Monroe Electric Generating Plant, at 15 (General Condition III) (incorporating projected annual and hourly emissions rates).

applicability. Letter from Frank Harbison, Sr. Lead Environmental Analyst, Entergy, to Larry Devillier, Asst. Administrator, LDEQ (Jan. 28, 1999). In addition, Entergy has provided various materials regarding maintenance activities, work needed to bring the plant back on line, permitting activities, and ERS decisionmaking. Letter from Gerald G. McGlamery, Louisiana Enviro. Admin., Entergy, to Hilry Lantz, Air Quality Div., LDEQ (Feb. 3, 1999); Memo from Entergy to EPA, "Actions Taken By Entergy At Monroe Generating Station" (w/ attachments).

time of shutdown, at least, it appears that LP&L did not envision a permanent shutdown, but rather a temporary shutdown to respond to market conditions at the time. <u>See</u> Memo from Entergy to EPA, "Actions Taken By Entergy At Monroe Generating Station."

During shutdown, LP&L/Entergy continued to conduct minimum maintenance at the plant. These activities primarily involved responding to problems with the dehumidification system. Entergy has provided maintenance records dating back to May 9, 1988 showing maintenance undertaken at the plant each year throughout the shutdown period and indicating that LP&L/Entergy staff made multiple inspection or maintenance visits to the facility.

During the period of shutdown, LP&L/Entergy also continued to pay annual state air quality maintenance fees. Entergy has provided receipts for these payments for the period October 7, 1988 through August 18, 1998. On December 14, 1995, Entergy applied for a title IV Acid Rain permit, which it received October 23, 1996.

Based on this record it would appear that Entergy did not intend at the time of shutdown, and has never intended, to permanently shut down the Monroe plant. On the other hand, it appears that Entergy has not, until very recently, had definite plans to restart these units.

The Louisiana Public Service Commission ("LPSC"), in a review of whether Entergy had properly included ERS facilities, including the Monroe plant, in its list of "available" facilities, '' found that Entergy had not adequately demonstrated that these ERS facilities would be returned to service. LPSC, Order No. U-020925-G (Nov. 18, 1998). Specifically, LPSC found

The dispute before the LPSC centered around a tariff agreement between Entergy companies whereby each company had to identify its available capacity and pay or receive compensation according to whether it produced power below or in excess of its listed available capacity. LPSC. Order No. U-020925 at 8-10. The agreement defined a unit as "available" if it was under the control of the system operator, was down for maintenance, or was in extended reserve shutdown with the intent of returning the unit to service at a future date. Id. at 10.

that Entergy had not analyzed the costs of returning the ERS units to service, could not give a time frame for returning any of the units to service beyond saying that they would be needed some time in the next 10 years, and had not made any efforts to confirm that they would be needed in the next 10 years. LPSC concluded that the fees resulting from Entergy's inclusion of the capacity of these ERS facilities could not be justified because Entergy had not made efforts to reach a decision "based on consideration of current and future resource needs, the projected length of time the unit would be in ERS status, the projected cost of maintaining such unit, and the projected cost of returning the unit to service."

The record before the EPA includes significant circumstantial evidence suggesting that Entergy has never intended the shutdown of the Monroe plant to be permanent. Despite this evidence, however, EPA continues to have serious doubts as to whether Entergy truly intended during much of the 11-year shutdown to expect to use the Monroe plant in the foreseeable future. Because restart of the plant more clearly triggers PSD as a major modification involving a change in the method of operation, EPA does not need to make a final conclusion regarding Entergy's regulatory status under the Reactivation Policy at this time.

2. Physical Changes Triggering PSD

As described previously, changes at a facility may be treated as a major modification subject to PSD review in one of two ways -- changes involving a physical change of the source and changes involving a change in the method of operation at the source. Entergy has submitted a description of the work, and

The disparity between the company's efforts to maintain the plant to avoid the appearance of permanent shutdown, and its failure to adequately demonstrate to the LPSC its plans to use the plant in the future, highlight one of the weaknesses of EPA's Reactivation Policy in determining the appropriate regulatory treatment of the restart of facilities after a lengthy shutdown. As a result, I have directed my staff to reevaluate EPA's Reactivation Policy to determine if steps can be taken to clarify the circumstances under which restart of a long-dormant source should be subject to new source review as a new source.

associated costs, being conducted in order to restart the three units at the Monroe plant. The total projected cost is approximately \$5.3 million. Of that, Entergy states that \$1.4 million will be spent on capital improvements. These include replacement of PCB-contaminated transformers, replacement of controls using mercury, and installation of continuous emissions monitoring equipment. The remaining work includes inspection and cleaning of equipment, some minor repairs of valves and piping, and replacement of auxiliary equipment such as batteries and lab equipment.

Analysis of whether these changes trigger PSD applicability must consider whether, "as a whole," the changes are exempt as routine maintenance, repair and replacement. See 40 CFR § 51.166(b)(2)(iii); L.A.C. 33:III.509(B). In our review of the proposed reactivation of the Cyprus Casa Grande RLA plant EPA explained:

Although the [contractor's] report notes the good condition of the acid plant and characterizes some of the needed work as "minor" or "moderate," viewed as a whole, the minimum necessary rehabilitation effort is extensive, involving replacement of key pieces of equipment . . . and substantial time and cost [(four months and \$905,000)]. In an operating plant some of the individual items of the planned rehabilitation, e.g. painting, if performed regularly as part of a standard maintenance procedure while the plant was functioning or in full working order, could be considered routine. Here, however, this and other numerous items of repair, as well as replacement and installation of new equipment, are needed in order for the RLA plant to begin operation. The fact that the plant requires four months of extensive rehabilitation work despite the adequate maintenance Noranda claims to have undertaken during the shutdown underscores the non-routine nature of the physical change that will occur at the plant.

Letter from David P. Howekamp, Director, Air Mgt. Div., Region IX, to Robert T. Connery, Holland & Hart (Nov. 6, 1987).

While the activities necessary to restart the Monroe plant might, collectively, appear to be part of a large, non-routine effort, EPA is not, at this time, making a finding as to whether

this effort amounts to a physical change of the source. Because restart of the plant most clearly amounts to a change in the method of operation, as described below, EPA need not reach a final conclusion on whether such concentrated efforts without repair or replacement of key pieces of equipment or key components should be considered routine.¹⁹

3. Change in the Method of Operation of the Monroe Plant

For the last eleven years the Monroe plant has been inoperative. To operate the plant now after such a long shutdown constitutes a change in the method of operation within the meaning of the PSD regulations. The mere fact that the plant is changing from a lengthy "non-operational" and "unmanned" condition, 20 to one in which the plant is fully operational, fits the common sense meaning of a "change in the method of operation."

The proposed changes in the operation of the plant do not qualify as exempt increases in either the hours of operation or the rate of production, see 40 CFR § 51.166(b)(2)(iii)(f), and L.A.C. 33:III.509(B), because they are not the type of changes intended to be covered by the regulatory exemption. As discussed above, the purpose of the "increase in hours" exception was to provide flexibility to allow sources to adjust their operations to take advantage of currently favorable or changing market conditions without requiring a PSD permit. Restart of the Monroe

¹⁹ It is worth noting that while the Cyprus rehabilitation effort included replacement of key pieces of equipment, the rationale for our conclusion in Cyprus Casa Grande turned on the non-routine collection of activities, and not on whether individual activities were themselves routine or non-routine.

In a 1994 letter to LDEQ, Entergy states that as a result of placing the plant in ERS status in 1988, "[the] plant is non-operational and unmanned." Letter from Entergy to Cheryl LeJeune, Office of Water Resources, LDEQ (July 18, 1994). Entergy also noted that, "It has not generated electricity for six years and has not operated on a routine basis since 1981." Letter from Entergy to Jayne Fontenot, Chief, Permits Issuance Section, EPA, Region VI (July 18, 1994).

plant neither calls for the same type of permitting flexibility nor can be considered a response to the kind of short-term, realtime market fluctuations envisioned by EPA in adopting the exemption.

This is not a situation where the sources's ability to plan ahead for permitting is constrained by the need for quick responses to short-term changes in the market. In its own analysis of PSD applicability, Entergy notes that unlike normal work outages where overtime is required to get the plants operational again, repairs at the Monroe plant will be conducted using "straight time" because "there will be no need to have the units available for dispatch in a short time frame." Memo from Mark G. Adams, Entergy to Myra Costello, Entergy (Aug. 3, 1998). Further, unlike the situations envisioned by the exemption, restart of a long-dormant facility involves permits for more than just air releases. Entergy has budgeted over \$175,000 to obtain all of the necessary permits including a new water discharge permit to reflect the change from inoperation. Where a facility requires numerous permits to once again operate, PSD permit review is no longer the solitary hindrance that the exemption was designed to avoid.

EPA also believes the decision to operate after eleven years of shutdown, while certainly motivated by changes in the marketplace, is not the kind of quick decision to respond to quick market fluctuations that EPA intended to allow without the burden of the PSD permitting process. In the WEPCO rulemaking, EPA discussed its view of the time period in which one would expect to see the effect of market fluctuations for the utility sector:²¹

By presumably allowing a utility to use any 2 consecutive years within the past 5, the rule better takes into consideration that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that

EPA's comments were made in the context of describing the representative period for determining baseline emissions from utilities, but the analysis of what constitutes normal operations is equally relevant to the discussion here.

affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By expanding a baseline for a utility to any consecutive 2 in the last 5 years, these types of fluctuations in operations can be more realistically considered, with the result being a presumptive baseline more closely representative of normal source operation.

57 Fed. Reg. 32314, 32325 (July 21, 1992). The eleven-year shutdown of the Monroe plant is well beyond the period in which one would expect to see changes in operation in response to the kind of market fluctuations addressed by the "increase in hours" exception. The decision to restart the plant after such a long period is a more fundamental change in the way the company has done and plans to do business. Entergy's decision to restart the Monroe plant looks less like a quick decision to take advantage of market conditions at an already-operational plant and more like a decision to begin operation of a source that has not previously participated in the market.

EPA has also made clear that the "increase in hours" exemption is not available where it would "disturb a prior assessment of a source's environmental impact." For the last eleven years, the State has carried the Monroe plant in its emissions inventory with zero actual emissions. From all accounts, the State has treated the plant as having no environmental impact. Restart of the plant would disturb this assessment and is not, therefore, entitled to the "increase in hours exemption."

The State's assessment of the plant's environmental impact is further demonstrated by the State's submittal for the Ozone Transport Assessment Group ("OTAG") modeling effort to assess interstate NOx transport contributions to ozone nonattainment in downwind States. In late 1995, 37 States including Louisiana, provided their emissions inventories to EPA for modeling and analysis. Fifteen of those 37 States (including Louisiana) claimed that actual emissions from sources in their State had no impact on downwind ozone nonattainment. In 1995, the Monroe plant was included in the State's emissions inventory and was still included in that inventory as having zero emissions when the ultimate transport analysis was concluded in 1997. OTAG used this inventory data to project emissions contributions and

nonattainment problems throughout the 37-State region through 2007. During this modeled period, emissions from the Monroe plant were assumed to be zero. Based in large part upon OTAG's modeling results, EPA declined to require Louisiana to revise its SIP as part of the recent "NOx SIP Call." EPA concluded that the weight of evidence did not support a finding that Louisiana made a significant contribution to downwind nonattainment. See, 62 Fed. Reg. 60318, 60340 (Nov. 7, 1997), 63 Fed. Reg. 57356, 57398 (Oct. 27, 1998). 23

EPA believes restart of the Monroe plant will constitute a change in the method of operation that is not otherwise exempted by the PSD regulations. The only possible exemption, the "increase in hours" exemption, simply was not intended to cover this kind of change. As a result, EPA must next consider whether the change in the method of operation will result in a significant net emissions increase, thereby triggering PSD applicability as a major modification.

4. Calculating Net Emissions Increase

Restart of the Monroe plant will result in emissions of NOx, SO2, CO, PM10 and VOC. As discussed previously, the emissions baseline for long-dormant sources such as the Monroe plant are

The Court of Appeals for the D.C. Circuit has stayed the SIP Call pending further order by the court. State of Michigan v. EPA, No. 98-1497 (D.C. Cir. Order filed May 25, 1999).

EPA conducted subsequent modeling efforts to evaluate the costs and air quality impacts associated with the proposed NOx SIP Call controls. This modeling did not rely on state inventory data. Instead, the approach looked at Energy Information Administration data regarding available power plants, and projected emissions based on future demand and likely order of dispatch (considering factors such as the plant's age and fuel type). This approach predicted future NOx emissions from Unit 12 of the Monroe plant of 148 tons per year. This amount of emissions corresponds to approximately 550 hours of full-load operation per year at Unit 12. Such minimal operations do not alter EPA's conclusions. No emissions were projected for any of the other units at the plant.

generally considered to be zero. EPA believes the zero emissions baseline is representative of normal source operations at the Monroe plant, which has had no emissions for the last eleven years.

The following table lists the significance levels, <u>see</u> 40 CFR § 51.166(b)(23)(i) and L.A.C. 33:III.509(B), in tons per year for each of the pollutants that could be emitted upon restart of the Monroe plant. In addition, the table lists Entergy's potential to emit (assuming full-time operation, as is reflected in the proposed operating permit) for these same pollutants. The potential to emit is assumed to be the source's "actual emissions" following the change in the method of operation. <u>See</u> note 16, supra.

POLLUTANT	SIGNIFICANCE LEVEL (TPY)	POTENTIAL TO EMIT (TPY)
NOx	40	4,972.65
SO2	40	679.84
со	100	361.65
PM10	15	32.46
voc	40	12.74

With the exception of VOC, restart of the Monroe plant will result in a significant emissions increase over its current zero emissions baseline for each of the listed pollutants.

The regulations define the contemporaneous period as extending back five years from the physical or operational change. No changes in emissions at the Monroe plant have been made during last 5 years because it has been shut down during this entire period. As a result there have been no increases or decreases in emissions that are contemporaneous with the change. See 40 CFR § 51.166(b)(3)(ii); L.A.C. 33:III.509(B). Therefore, the net emissions increases from start-up of the Monroe plant would be approximately those stated in the chart above. Hence, EPA agrees with Petitioner that the title V permit for the Monroe plant should be revised to assure compliance with the Louisiana SIP PSD requirements because start-up of the plant would be subject to PSD as a major modification under the Clean Air Act, 40 CFR § 51.166, and L.A.C. 33:III.509(B).

V. NSPS APPLICABILITY

Petitioner claims that the maximum capacity of the affected facilities at the Monroe plant may have been increased by some unknown method at some time between 1976 and the time of the title V application without being subject to NSPS review. Petitioner points to differences in reported emission capacities that suggest a modification has occurred at the Monroe plant. In the April 27, 1976 compliance report from the City of Monroe to the Louisiana Air Control Commission, the total capacity of the Monroe plant was reported as 1365 MMBtu/hr. In the September 18, 1996 title V permit application, however, Entergy reports the Monroe plant's capacity as 1961 MMBtu/hr. While EPA believes that Entergy has adequately explained this discrepancy in reported capacities (see below), EPA nonetheless evaluates in this section whether the changes to the Monroe plant might otherwise be subject to NSPS.

Section 111 of the Clean Air Act requires EPA to adopt standards of performance for stationary sources constructed or modified after the date the standards are proposed. CAA §§ 111(a)(2),(3) and (b)(1); see also 40 CFR § 60.1.24 Unlike the PSD program, reactivation of long-dormant facilities is not considered construction of a new source. See Memo from Edward E. Reich, Dir., Div. Of Stationary Source Enf., to Sandra S. Gardebring, Dir., Region V Enf. Div. (Oct. 30, 1980). Installation of Units 10, 11 and 12 occurred prior to adoption of all NSPS regulations. Thus, to determine NSPS applicability for restart of the Monroe plant, EPA need only consider whether the affected facilities have been modified or reconstructed. See 40 CFR §§ 60.14 and 60.15.

A "modification" for purposes of NSPS applicability is defined as:

²⁴ Louisiana has adopted the federal NSPS regulations by reference. <u>See</u> L.A.C. 33:III.3003(A). For purposes of this section, only the federal regulations are cited.

The first NSPS for fossil-fuel-fired steam generators applied to sources for which construction was commenced after August 17, 1971. 40 CFR, Part 60, subpart D.

(A) ny physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

40 CFR § 60.1. As with PSD, the analysis of whether an activity constitutes a modification is a two-part test. The first step --identifying a physical or operation change -- is similar to the first step for finding a PSD modification. The second step of the NSPS analysis -- finding an emissions increase -- differs from the emission netting step of PSD.

To find an increase in emissions, EPA compares the hourly emissions capacity of an affected facility before and after the change. See 40 CFR § 60.14; see also WEPCO, 893 F.2d at 913. The changes at the Monroe plant do not appear to be of the type that would increase the hourly emissions capacity of the affected facilities. As described above, the major work being performed at the Monroe plant appears to involve upgrading certain controls, replacing PCB-containing transformers and some repairs and maintenance of the boilers and associated auxiliary equipment. Based on the information currently before it, EPA believes the affected facilities could operate at the projected capacities with or without the changes that have occurred at the source. If, after further investigation, EPA finds that changes to the facility in fact will increase the emissions capacity of the affected facilities, EPA will revisit the question of NSPS applicability.

In response to Petitioner's claims that reported emissions capacities had increased, Entergy explained that values derived from fuel consumption in 1975 were erroneously reported as maximum heat input values and appeared to be less than those stated in the permit application. Entergy's explanation appears to be confirmed by reference to specification sheets for the boilers. Because the manufacturer's specification sheets for the boilers reflect the same heat input values as represented in the permit application, EPA concludes that, standing alone, the differences in the reported emissions capacities, do not demonstrate a change in the emissions capacity of the affected

facilities.

NSPS may also be triggered, irrespective of changes in emission capacities, if the changes to the affected facility amount to reconstruction of the facility. 40 CFR § 60.15(b). A facility is considered to be reconstructed when the represented fixed capital costs of new replacement components to reactivate the facility exceed 50% of the fixed capital costs required to construct a comparable new facility. 40 CFR § 60.15(b). Here, Entergy has projected the total cost (capital and O&M) to restart all affected facilities at the Monroe plant will be approximately \$5.3 million. Entergy estimates approximately \$1.4 million of these costs will be capital expenditures. Of these capital expenditures, it appears that at least half relate to replacement of PCB-containing transformers and thus do not relate to changes to the affected facilities. Given the small capital costs associated with reactivation of the affected facilities, it does not appear that the restart activities at the Monroe plant would trigger NSPS based upon a reconstruction analysis.

VI. RCRA DISPOSAL REQUIREMENTS

Entergy's permit application contains reference to two different procedures to remove iron oxide and copper from the boilers. One procedure involves using up to 30,000 pounds of ethylenediaminetetraacetic acid ("EDTA"). Spent boiler cleaning solutions containing this chemical and scavenged metals are injected into the boiler for combustion. The Petitioner claims that Entergy's permit application does not contain sufficient information concerning the analysis of typical spent boiler cleaning solutions nor citation to any regulatory provision that would exempt boiler cleaning solutions from RCRA disposal The Petitioner further asserts that if the spent regulations. boiler cleaning solutions exhibit RCRA hazardous waste characteristics, disposal would be prohibited unless the facility obtains a RCRA permit, became regulated under EPA's Boiler and Industrial Furnace regulations, or otherwise demonstrated that the spent boiler cleaning solution complied with EPA's "comparable fuels" specification.

To justify exercise of an objection by EPA to a title V permit pursuant to section $505\,(b)\,(2)$ of the Act, the Petitioner must demonstrate that the permit is not in compliance with the

requirements of the Clean Air Act, including the requirements of the Louisiana SIP. RCRA requirements are not applicable requirements of the Act. See 40 CFR § 70.2. Therefore, this issue cannot be addressed as part of the petition process. However, the emissions themselves would be regulated under Louisiana's Air Quality regulations and federal/state hazardous waste requirements.

Under Louisiana Air Permit General Condition XVII, Entergy must submit any small emissions (generally less than 5 tpy in total) resulting from routine operations that are predictable, expected, periodic, and quantifiable to the Louisiana Air Quality Division for approval as authorized emissions. If the emissions are considered non-routine, Entergy must apply for a variance under L.A.C. 33.III.917. Thus, the emissions from the combustion of the spent boiler cleaning solutions are regulated under Louisiana's air quality regulations. In addition, if the spent boiler cleaning solution were to exhibit RCRA hazardous waste characteristics, Entergy would be required to comply with all applicable federal and state hazardous waste management requirements.

VII. CONCLUSION

For the reasons set forth above, I find that the proposed title V permit fails to assure compliance with applicable PSD requirements set forth in the Louisiana SIP. As a result, I partially grant the February 9, 1999 petition requesting that the Agency object to the proposed Entergy permit, and I hereby object to issuance of the proposed Entergy Permit. I deny the remainder of the February 9, 1999 petition. Pursuant to section 505(b) of the Act and 40 CFR § 70.8(d), LDEQ shall not issue the permit unless it is revised in accordance with this Order.

Date: JUN 1 1 1999

Carol M. Browner Administrator

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE)) Judge Bernard A. Friedman)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.)))
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY	ý))
Defendants.))

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-F

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
215 Fremont Street
San Francisco. Ca. 94105

November 6, 1987

Robert T. Connery, Esq. Holland & Hart P. 0. Box 8749 Denver, Colorado 80201

Re: Supplemental PSD Applicability Determination Cyprus Casa Grande Corporation Copper Mining and Processing Facilities

Dear Mr. Connery:

This is a supplemental determination regarding the applicability of prevention of significant deterioration (PSD) provisions under sections 160-169 of the Clean Air Act, 42 U.S.C §9 7470-7479, and EPA's PSD regulations, 40 C.F.R. S 52.21 to the above-referenced facility, located near Casa Grande, Arizona. This determination supplements the determination set forth in a May 27, 1987 Memorandum from John S. Seitz, Director, Stationary Source Compliance Division, EPA, and in my May 29, 1987 letter to Roger M. Ferland, Streich, Long, Weeks and Cardon, Phoenix, Arizona, attorney for Noranda Lakeshore Mines, Inc., which formerly controlled the Casa Grande facility. For the reasons discussed below, EPA today (1) reaffirms and incorporates by reference herein its earlier determination that reactivation of the Roaster/Leach/Acid (RLA) plant at the Casa Grande facility would constitute a major -new source within the meaning of Part C of the Clean Air Act and EPA's regulations issued thereunder; and (2) determines that even if the reactivated RLA plant would not be subject to PSD as a new source, the start-up would also constitute a major modification for PSD purposes. Accordingly, Cyprus Casa Grande Corporation (Cyprus) must obtain a PSD permit before beginning construction on any of the rehabilitation activities necessary for start-up of the RLA plant.

1. THE NEED FOR THIS SUPPLEMENTAL DETERMINATION

The earlier applicability determination by Mr. Seitz and myself was in response to requests by Noranda that focused exclusively on the question whether start-up of the RLA plant would render the facility subject to PSD as a major new source pursuant to EPA's shutdown/reactivation policy. My review of



C1N30B6RM0064

the administrative record of that matter has confirmed that Noranda did not request EPA to consider, and EPA did not consider, whether the RLA plant would be subject to PSD upon reactivation as a major modification under the Act and the PSD regulations.

Following EPA's earlier determination, Noranda transferred its interest in the facility in question, including the RLA plant, to Cyprus. Cyprus then sought review of EPA's determination in the court of appeals. Cyprus Casa Grande Corp. v. EPA, No. 87-7322 (9th Cir.). In a Civil Appeals Docketing Statement filed with the Ninth Circuit on July 30, 1987, Cyprus identified under category I., "Issues to be Raised on Appeal," the following item:

(2) Whether Petitioner's existing RLA plant has been subject to a "major modification," 40 C.F.R. § 52.21(b)(2), which would require a PSD preconstruction permit.

Thus, it is clear that if this matter is adjudicated by the court of appeals, it likely would raise issues beyond the scope of the consideration previously given by EPA and Noranda. This in turn raises the distinct possibility that litigation based on EPA's prior determination would not finally resolve the question of whether PSD applies to the start-up of the RLA plant, and that a subsequent round of judicial review would be necessary. Such a scenario would waste the resources of the court, EPA, and Cyprus, and would be contrary to Cyprus' stated interest in a quick resolution of environmental requirements for the project.

Accordingly, I believe it is appropriate at this time for EPA to determine whether the prospective start-up of the RLA plant by Cyprus would constitute a major modification for PSD purposes. This determination can be made on the basis of the record created in conjunction with the earlier reactivation determination by Mr. Seitz and myself. In addition, because that earlier determination was directed to Noranda in response to requests by that company, and in view of the evident controversy surrounding that determination, it is also appropriate to reconsider its application to Cyprus, as the new owner of the facility.

II. RECONSIDERATION OF WHETHER START-UP OF THE RLA PLANT IS SUBJECT TO PSD AS A MAJOR NEW SOURCE UNDER EPA'S REACTIVATION POLICY.

After reviewing the administrative record in this matter, I find no reason to disagree with EPA's longstanding shutdown/reactivation policy or its application to the set of circumstances presented by Noranda. Hence, EPA has no basis to change its earlier determination that start-up of the RLA plant would be subject to PSD requirements as a "reactivation," except insofar as the intervening transfer of the facility to Cyprus

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would require a different result.

There is one key point that emerges from the transfer to Cyprus: It represents a further attenuation, both in the chain of ownership and in time, between shutdown of the RLA plant in 1977 and its prospective reactivation. A change in ownership does not, standing alone, render a stationary source subject to PSD provisions. See 40 C.F.R. § 52.21(b)(2)(iii)(g). However, the circumstances surrounding a change in ownership may be probative of whether the shutdown of the source should be deemed permanent, which is the key analysis that must be made under EPA's reactivation policy.

In this case, the inference that the shutdown was permanent is even stronger after the transfer to Cyprus than it was when Noranda was in control. This is so because by the time Cyprus gained control, the RLA plant had already been shut down for ten years, as opposed to two years when Noranda entered the scene. It addition, by the time Cyprus took over, the RLA plant was no longer in the state's emission inventory and did not possess operating permits. Thus, from the inception of Cyprus' ownership, every indication is that Arizona considered the facility to be permanently closed.

The transfer to Cyprus serves to strengthen the reactivation determination EPA made as to Noranda. Accordingly, my determination is that the start-up of the RLA plant by Cyprus would constitute a reactivation subject to PSD requirements as a new source.

III. WHETHER START-UP OF THE RLA PLANT IS SUBJECT TO PSD REQUIREMENTS AS A MAJOR MODIFICATION.

Even if the RLA plant were not subject to PSD as a new source under the reactivation policy, it would be subject anyway if the start-up were deemed to be a "major modification" within the meaning of the Act and 40 C.F.R. § 52.21.

The central thrust of the Clean Air Act's PSD major modification provisions is that significant actual emissions increases -- i.e., those which have substantial consequences for ambient pollution concentrations and, hence, the states' need to account for such pollution -- should be brought under PSD review. See Alabama Power Co. v. Costle, 636 F.2d 323, 400 (D.C. Cir. 1979). EPA followed the lead of the court in formulating the major modification provisions of the PSD regulations by focusing the regulatory definitions on actual emissions rather than a source vs potential to emit. See 45 Fed. Reg. 52700, col. 2-3. EPA also promulgated a narrow and limited set of exclusions in Its major modification regulations, but only to allow for routine changes in the normal course of business, where PSD

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review would be unduly disruptive. See 40 C.F.R. \$52.21(b)(2)(iii)(a) and (f).

Determining whether a major modification will occur at a particular source requires a sequential analysis of several factors. These factors are discussed in the preamble to the PSD regulations at 45 Fed. Reg. 52676, 52698 (August 7, 1980). The factors may be grouped under two basic questions: Would the start-up entail a "physical change in or change in the method of operation of a major stationary source"? If so, would the change "result in a significant net emissions increase of any pollutant subject to regulation under the Act"? See 40 C.F.R. § 52.21 (b)(2)(i).

A. Physical Change or-Change in the Method of Operation of the RLA Plant.

This requirement of a major modification is satisfied if either a physical or operational change would occur. In this case, the start-up would constitute both a physical and an operational change.

1. Physical-Change.

The rehabilitation work necessary to make the Cyprus RLA plant operational would constitute a "physical change" at a major stationary source. */

EPA is aware of three reports addressing the rehabilitation work necessary to restart the RLA plant. By letter dated March 20, 1987, Noranda submitted the most recent evaluation of the minimum rehabilitation work necessary to start up the plant. The evaluation was prepared in March 1987 by E & C International ("E & CI") for the Cyprus Minerals Company and was based upon a three day inspection of the plant and review of equipment, support installation and existing piping, instruments and electrical switchgear. Noranda also submitted a June 1986 report prepared by the Ralph M. Parsons Company, also for Cyprus, which estimated "nominal cost" of \$1.836,000 for refurbishing the RLA plant, plus "worst case add-on" costs of \$906,000. However, the Parsons report was an "order of magnitude"

As noted in Noranda's original Request for opinion dated September 12, 1986, sulfur emissions from the plant are 4.3 tons per day, equivalent to approximately 1500 tons per year, and thus greatly exceeding both the 100 ton per year threshold limit applicable to the primary copper smelter category or the 250 ton per year threshold for an "unlisted" major stationary source under 40 C.F.R. 52.21(a)(1).

scoping report, and based these cost estimates upon the Company's experience rehabilitating similar processing facilities rather than upon a detailed plant inspection. In addition, Noranda's original September 12, 1986 Request for opinion contained a February 1982 survey of rehabilitation work estimating a total cost of \$347,000 and monthly maintenance reports for April-July 1982 indicating that some rehabilitation work occurred in this period. From among these three estimates of necessary rehabilitation work, the E & CI evaluation can most reasonably be relied upon. It is the most current and comprehensive and was based upon an actual plant inspection by outside consultants.

The E & CI report called for the following rehabilitation:

- 1) replacing of the thickener tanks in the roaster plant's Counter Current Decantation (CCD) circuit and repairing the "significantly" damaged foundation for the CCD thickener foundation;
- 2) installing new external insulation for both fluid bed roasters and gas cyclones;
- 3) "minor" refractory repairs in one roaster;
- 4) "minor" structural repairs and painting throughout the roaster plant's steel structure to address "significant" corrosion damage;
- 5) replacing a "moderate" amount of piping and valves in the roaster plant:
- 6) restoring or replacing of stainless steel pumps at the acid plant;
- 7) installing a pressure sand filter;
- 8) rebuilding the underflow pumps in the CCD circuit.

The E & CI report concluded that the work necessary to prepare the facility for operation could be done in three to four months at a cost of \$905,000, without any contingency calculated. Contingency costs could significantly exceed this amount. */ Even without factoring in contingent costs, \$905,000 represents roughly 10% of the replacement cost of a new roaster. See Attachment 2 of March 27, 1987 letter from Roger Ferland.

The E & CI report recommended adding on a 15% contingency for craft labor and materials and the Parsons report estimated \$900,000 for "worst case" add-on costs. Information obtained during an EPA site visit confirmed that rehabilitation would require four months of double shifts.

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Under the PSD definition of "major modification", a physical change does not include "routine maintenance, repair and replacement." 40 C.F.R. § 52.21(a)(2)(iii)(a). Although the E & CI report notes the good condition of the acid plant and characterizes some of the needed work as "minor" or "moderate." viewed as a whole, the minimum necessary rehabilitation effort is extensive, involving replacement of key pieces of equipment (e.g., the CCD thickener tanks, pumps, external insulation), and substantial time and cost. In an operating plant some of the individual items of the planned rehabilitation, e.g. painting, if performed regularly as part of standard maintenance procedure while the plant was functioning or in full working order, could be considered routine. Here, however, this and other numerous items of repair, as well as replacement and installation of new equipment, are needed in order for the RLA plant to begin operation. The fact that the plant requires four months of extensive rehabilitation work despite the adequate maintenance Noranda claims to have undertaken during the shutdown underscores the non-routine nature of the physical change that will occur at the plant. Thus, given the extent and nature of the repair. rebuilding and replacement of important equipment necessary to make the RLA plant operational, the rehabilitation work simply cannot be considered the "routine maintenance, repair and replacement" which is excluded from PSD review.

Change in the Method of operation.

The prospective start-up of the RLA plant after a ten-year shutdown would also constitute a change in the method of operation within the meaning of the PSD regulations.

As discussed above, the PSD major modification rules focus on changes in actual emissions. In general, changes at existing facilities that significantly increase actual emissions must undergo PSD-review. Yet, in adopting the PSD rules EPA-also recognized that Congress did not intend to require preconstruction permits for a routine change in the hours or rate of operation. EPA believed that "such a requirement would severely and unduly hamper the ability of any company to take advantage of favorable market conditions." 45 Fed. Reg. 52704, col. 2. Accordingly, the PSD regulations exclude from the definition of physical or operational change "an increase in the hours of operation or in the production rate." 40 C.F.R. § 52.21 (b)(2)(iii)(f). However, I believe it is clear that in adopting this exclusion. EPA did not intend to remove PSD coverage in circumstances such as those presented by Cyprus. Rather, EPA limited this exclusion to situations where it would not interfere with a state's efforts in air quality planning when, in the preamble to the PSD regulations, it noted:

At the same time, any change in hours or rate of operation that would disturb a

- 7 -

prior assessment of a source's environmental impact should have to undergo scrutiny.

45 Fed. Reg. 52704, col. 2-3. Thus, EPA disallowed the exclusion where the increase would not be allowed under a preconstruction permit. 40 C.F.R. § 52.21(b)(2)(iii)(f).

In this case, the RLA plant was not required to obtain a preconstruction permit when it was originally erected, because it predated the PSD program. Thus, the present situation is not squarely addressed by the relevant regulatory provision. Nevertheless, EPA's original intention to disallow the exclusion where it would "disturb a prior assessment of a source's environmental impact" leads me to conclude that the exclusion should not be applied here. This is so because our present assessment as well as that of the State of Arizona, is that the RLA plant in its current non-operating condition has no environmental impact. This is evidenced in part by the removal of the plant from the state's emission inventory and the surrender of operating permits. An additional factor is the simple physical fact that the RLA plant has had zero emissions for ten years. I believe that this result is a reasonable interpretation of the PSD regulations, and in keeping with the statutory purposes. (See in particular Clean Air Act section 160(3) and (S)).

3. Combination.

In any event, it seems undeniable, when one looks at both the physical and operational changes the company is proposing to make, that the reactivation constitutes a fundamental alteration in the character of the plant, one that is neither everyday nor routine. Nor is the reactivation deserving of special treatment because of a high frequency of changes at the facility or insusceptibility to event-by-event permitting.

B. <u>Net Emissions Increase</u>.

Whether a significant "net emissions increase" would occur is itself a multistep analysis. The first step is to determine whether the particular physical or operational change in question would itself result in a significant increase in "actual emissions." See §52.21(b)(3)(i)(a) and (b)(21). If so, the second step is to identify and quantify any other prior increases and decreases in "actual emissions that would be "contemporaneous" with the particular change and otherwise creditable. See § 52.21(b)(3)(i)(b). The third step is to total the increase from the particular change with the other contemporaneous increases and decreases. See § 52.21(b)(3)(i)(b). If the total would exceed zero, then a "net emissions increase" would result from the change. Each of these factors is analyzed below in the context of the prospective start-up of Cyprus" RLA plant.

- 8 -

. Increase in Actual Emissions.

The start-up of the RLA plant would result in an increase in actual emissions within the meaning of the PSD regulations.

This calculation is made by comparing actual emissions as of a "particular date" -- i.e., immediately prior to the physical or operational change in question -- with the emissions from the source after the change is made. The regulations provide that actual emissions shall be the rate at which the source actually emitted the pollutant during the two-year period immediately preceding the particular date (the date of the change), unless EPA determines that a different two-year period is more representative of normal source operation. 40 C.F.R. § 52.21 (b)(21); see.also 45 Fed. Reg. 52718, col. 2.

In this case, the pollutant in question is sulfur dioxide (502), and emissions during the two-year period preceding start-up of the RLA plant are zero. I believe that this period is representative of normal source operations, since emissions have been zero during each of the last ten years while the plant has been shut down. Conversely, given this operational history, I do not believe that emissions during the one year in which the RLA plant was functioning is more representative of normal operations at the, Casa Grande facility. After start-up, emissions will be approximately 1500 tons per year. Thus, the entire amount of emissions after start-up will be considered an increase in actual emissions, and it is obviously significant. 40 C.F.R. § 52.21(b)(23)(i).

Contemporaneous Increases and Decreases in Actual Emissions.

No other Increases or decreases in actual emissions that would be contemporaneous with the start-up of the RLA plant have been brought to EPA's attention.

The regulations define the contemporaneous period as extending back five years from the physical or operational change, 40 C.F.R. § 52.21(b)(3)(ii), and no changes in emissions at the RLA plant have been made during this period because it has been shut down during this entire period. It should be pointed out in this regard that EPA chose the "fairly large" five-year contemporaneity period over a shorter period in response to industry commenters on the PSD regulations, who had urged that no time limit be placed on crediting of prior emissions decreases. The Agency believed five years to be adequate to accommodate a normal period for corporate planning. See 45 Fed. Reg. 52701, col. 1. Thus, EPA specifically considered and rejected an arrangement whereby an emissions decrease, such as that represented by the ten-year shutdown of the RLA plant, potentially could be credited upon start-up for purposes.of determining whether a major modification would occur.

- 9 -

Net Emissions Increase.

Because the actual emissions increase from start-up of the RLA plant would be approximately 1500 tons per year, and there are no contemporaneous emissions increases or decreases, the net emissions increase from start-up would also be approximately 1500 tons per year. This amount is well above the 40 tons per year "significance" level for S02. 40 C.F.R. § 52.21(b)(23)(i). Hence, the start-up would constitute a major modification within the meaning of the Clean Air Act and 40 C.F.R. § 52.21, and Cyprus must obtain a PSD permit prior to construction for this reason alone.

IV. SUMMARY.

Whether the prospective start-up of the RLA plant is viewed under EPA's reactivation policy or under its major modification regulations, I conclude that PSD requirements apply. This consistency of results is not surprising, because both the policy and the regulations address the same general principle that significant increases in actual emissions of air pollution, not already accounted for in air quality planning or involving significant capital investment, be reviewed under the PSD provisions of the Clean Air Act. I hope that in light of this supplemental determination, Cyprus will better understand EPA's insistence that the RLA plant undergo the normal PSD review procedures. I am also aware of Cyprus' desire to rehabilitate the RLA plant and recommence operations as soon as possible. EPA will do its best to accommodate this desire, consistent with its need to avoid undue disruption of its other PSD regulatory responsibilities.

Sincerely,

David P. Howekamp Director Air Management Division

cc: Lee Lockie John Seitz

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,)	Civil Action No. 2:10-cv-13101-BAF-RSW
and) NATURAL RESOURCES DEFENSE) COUNCIL, and SIERRA CLUB)	Judge Bernard A. Friedman Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors) v.)	
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)	
Defendants.	

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-G

December 12, 1995

(AT-18J)

Don Smith, Supervisor
Permit Unit II
Permit Section
Air Quality Division
Minnesota Pollution Control Agency
520 Lafayette Road
St. Paul, Minnesota 55155

Dear Mr. Smith:

I am writing in regard to a letter from Jenny Reinertson of your staff to Rachel Rineheart of my staff dated November 22, 1995, concerning a proposed project at Fairmont Utilities. Due to the unique circumstances of this case, Ms. Reinertson has requested that the United States Environmental Protection Agency (USEPA) review the material provided and determine if the proposed modification is exempt from Prevention of Significant Deterioration (PSD) review.

According to the information provided by Ms. Reinertson, Fairmont Utilities intends to make modifications to two existing boilers. These boilers currently burn coal, but have the capability to burn natural gas. However, rather than using the existing burner configuration, the utility will be replacing the existing atmospheric burners (two in each boiler) with a matrix of 30 burners that will be placed on top of the existing coal grate. Fairmont Utilities believes that the modification would be exempt from PSD review under 40 CFR 52.21(b) (2) (iii) (e) (1) which states that a physical change or change in the method of operation shall not include use of an alternative fuel which "the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166."

USEPA agrees with the Minnesota Pollution Control Agency's determination that this proposal is a modification, and would be subject to PSD if it resulted in a significant increase in a criteria pollutant. Although the boiler may be capable of accommodating natural gas without modification, Fairmont Utilities is proposing to alter the design of the boiler. The change to the burner array is not considered as routine maintenance, repair, and replacement, and goes beyond what was contemplated in the June 7, 1981 memorandum from James T. Wilburn, USEPA Region IV to Richard Grusnick, Alabama Department of Environmental Management which was referenced by Fairmont Utilities.



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Although 40 CFR 51.21(b) (2) (iii) (e) (1) does not apply to this modification, we would encourage the source, as MPCA has done, to submit this project to MPCA as a pollution control project. If you have any questions in regard to this letter, please contact me or Rachel Rineheart of my staff at (312) 886-7017.

Sincerely yours,

/S/

Robert Miller, Chief Permits and Grants Section Air Toxics and Radiation Branch

EPA5P0H001864

CIN30B6RM0210

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

Civil Action No. 2:10-cv-13101-BAF-RSW
))
) Judge Bernard A. Friedman
Magistrate Judge R. Steven Whalen
)
)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-H

Day 1 19

Roger Randolph, P.E. Director, Air Pollution Control Program Missouri Department of Natural Resources Jefferson State Office Building P.O. Box 176 Jefferson City, Missouri 65102

Dear Mr. Randolph:

re: Sibley power plant, Jackson County, Missouri

An article in <u>The Kansas City Times</u> on November 15, 1989, states that the Missouri Public Service division of UtiliCorp United, Inc. has announced plans to physically modify and extend the life of the above-referenced steam-electric generating station.

The possible applicability of the NSPS and/or the PSD regulation to such projects was addressed by the EPA during September and October 1988 in various documents relating to a proposed project by the Wisconsin Electric Power Company (WEPC). We sent a copy of pertinent documents regarding the matter to the MDNR on November 16, 1988, and November 30, 1988. The documents are also available on the NSR Bulletin Board as NSR4.PSD. If the article is reasonably accurate, many of the issues that are discussed in the above-mentioned EPA documents may have to be considered in review of the Sibley project. Wisconsin Electric subsequently sued EPA regarding EPA's preliminary opinion that the WEPC project might be subject to both PSD and NSPS requirements. The case has been argued in court, but no decision has been rendered. We will keep you informed of progress. The discussion of potential NSPS and/or PSD applicability to the Wisconsin Electric project is quite extensive -- many of the points may be applicable to the proposed Sibley project.

PSD/NSPS:

Arguments that extension of life projects are routine maintenance, repair, or replacement should be carefully scrutinized by review agencies. Routine maintenance, repair, or replacement generally means regular, customary, or standard undertakings for the purpose of maintaining the plant/unit in its <u>present</u> condition. Projects that will significantly enhance the present efficiency or capacity of the plant/unit and that will substantially extend the useful economic life of the plant/unit generally should not be

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considered routine maintenance, repair, or replacement. A common sense approach is suggested. If emissions will increase as a result of said project, PSD and/or NSPS applicability may be triggered.

- Projects that will allow a plant/unit to increase the facility's production rate or hours of operation beyond its current capabilities generally do not qualify for the exemptions regarding production rate or hours of operation. This is important in that current capabilities may be significantly less than the original design.
- Physical changes that will enable a unit/source to achieve its original design capacity (assuming a deterioration of operating capacity over time) should be viewed as an increase of production <u>capacity</u>, rather than an increase of production <u>rate</u>; the latter is exempted from being considered a physical/operational change, the former is not so exempted.
- Both regulations are premised, in part, on an emission increase. NSPS (re: modification) is evaluated on an affected facility and a kilogram per hour basis. PSD is evaluated on a plantwide and a ton per year basis. Under NSPS, the affected facility may be a single emission unit or a group of emission units, depending on the source category involved. For boilers, the NSPS affected facility is each boiler unit. If an emissions increase will not occur at the affected facility, NSPS (re: modification) is not triggered. If an emissions increase at the source (PSD) will not occur, PSD is not triggered.
- The NSPS (reconstruction) provisions are not premised on an emission increase at the affected facility. Of preliminary concern is the replacement of component parts and the costs of said replacement relative to the cost of a comparable new facility.

NSPS:

- <u>Permit restrictions</u> such as operating hour restrictions, fuel type (such as low sulfur coal) restrictions, or usage (e.g., gallons of oil per year) restrictions may <u>not</u> be used to exempt facilities from NSPS applicability.
- <u>Physical restrictions</u>, however, may be used to exempt facilities from NSPS applicability. Such restrictions may include redesign of the unit to limit heat input, the type of fuel the unit will be able to burn/process, etc..
- Pollution control equipment may be considered regarding the facility's actual emission rate.

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- The maximum current operating levels must be used (not previous operating capabilities). The current maximum operating level to be used to determine the "before" emission rate must be achievable and sustainable. The "after" emission rate must be the maximum capacity resulting from the physical/operational changes that have been made to the unit/facility.
- The before and the after fuels that are assumed (or burned during testing) must be the same for purposes of determining emission change. For example, the "after" emissions may not be based on low sulfur coal if the "before" emissions is based on high sulfur coal if the modified boiler will have the physical ability to burn low sulfur and high sulfur coal.
- Emission reductions at the <u>facility</u> may be creditable; other emission reductions at the <u>source</u> are not creditable.

PSD:

- Permit limitations/restrictions may be imposed to restrict the emission potential of a source. Said restrictions/ limitations must be enforceable by EPA.
- Net emission change is based on the difference between the representative <u>actual emissions</u> of the source before the physical/operational change and the <u>potential-to-emit</u> of the unit/source after the physical/operational change.
- Pollution control equipment may be considered to the extent the <u>effect</u> of said equipment is federally enforceable (i.e., enforceable by EPA).
- Emission reductions at the <u>source</u> may be creditable.

The NSPS and the PSD applicability decisions should be performed separately because of the unique differences between the regulations regarding applicability.

If requested to do so, we will assist MDNR in its evaluation of the proposed Sibley project. We request that MDNR keep us informed of its review and of its preliminary and final decisions regarding the proposed project by providing us with timely submittal of correspondence between the owner/operator (and its consultants, representative, etc.) and the MDNR.

C1N30B6RM0107

If you have any questions pertaining to this letter, please contact me or Dan Rodriguez of my staff at 913/236-2896.

Sincerely,

Charles W. Whitmore Chief, Air Compliance Section

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IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB)) Judge Bernard A. Friedman) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.)))
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY	
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-I

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

September 13, 2000

4APT-ARB

Mr. Jimmy Johnston Georgia Environmental Protection Division Air Protection Branch 4244 International Pkwy., Suite 120 Atlanta, GA 30354

SUBJ: No. 1 Recovery Furnace Maintenance, Repair and Replacement Project PCA Pulp and Paper Mill Valdosta, Georgia

Dear Mr. Johnston:

Thank you for requesting assistance from the U.S. Environmental Protection Agency (EPA), Region 4, in making a prevention of significant deterioration (PSD) applicability determination. This determination is for a proposed maintenance, repair and replacement project involving the No. 1 Recovery Furnace at the Packaging Corporation of America (PCA) pulp and paper mill in Valdosta, Georgia. The question at issue is whether the proposed project qualifies as "routine maintenance, repair and replacement" and is therefore not a physical change or change in the method of operation under PSD regulations.

In this letter, we respond to your request based on how we believe such a request would be resolved under the federal PSD rules in Title 40 Code of Federal Regulations and under EPA policies. Our response does not represent how you must interpret the PSD requirements that EPA has approved into Georgia's state implementation plan, nor does it represent final agency action. Instead, this letter provides guidance for you to consider in your role as the PSD permitting authority.

The maintenance, repair and replacement actions scheduled for No. 1 Recovery Furnace consist of the following as listed in a letter from PCA to the Georgia Environmental Protection Division (GAEPD) dated June 8, 2000: (1) replacement of water tubes in lower furnace walls from mid-wall headers to the bottom, including the floor tube section; (2) replacement of water tubes in upper furnace walls, including the roof tube section; (3) removal and replacement of outer casing, insulation and brick work (for access) from lower furnace to economizer outlet; (4) replacement of economizer casing, lagging and insulation; (5) replacement of dissolving tank shell after removal of existing tank shell for access; (6) annual inspection and repair, including tube thickness testing in the balance of the furnace, and inspection and repair as necessary of the



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electrostatic precipitator, air heater, liquor heater, cascade, auxiliary equipment and ductwork; and (7) removal of insulation and lagging on electrostatic penthouse for inspection, with repair as necessary. PCA estimates that the total cost for the planned project is \$4,605,000, of which the cost for tube-related work is expected to be \$3,577,000.

Region 4's opinion is that the planned No. 1 Recovery Furnace maintenance project is not routine. This opinion has been reviewed by the Region 4 Environmental Accountability Division and by EPA's Office of Air Quality Planning and Standards, Office of Enforcement and Compliance Assurance and Office of General Counsel.

The reasoning that led us to our opinion is as follows:

- 1. EPA's longstanding practice has been to consider the nature, extent, purpose, frequency, and cost of a proposed project, as well as other relevant factors, to arrive at a commonsense understanding of whether a proposed project is routine.
- EPA has affirmed in previous opinions that the routine activity exception has a narrow scope and should generally be applied only to actions that are regular, customary, repetitious, and undertaken as standard practice to maintain a facility in its present condition.
 - 3. In terms of nature, extent and frequency, our understanding is that the entire lower furnace wall water tube section, floor tube section, upper furnace wall tube section, and roof tube section in No. I Recovery Furnace have never been replaced simultaneously during a single maintenance project throughout the 48-year history of the furnace. We further understand that the upper furnace wall tube section and roof tube section in No. I Recovery Furnace have never been replaced previously. The infrequent occurrence of maintenance projects of this nature and extent is also indicated by the 48-year operating history of No. 2 Recovery Furnace and the 32-year operating history of No. 3 Recovery Furnace.
 - The estimated cost of the maintenance project (\$4.6 million) is well within the range of
 costs that have been judged by EPA as indicative of non-routine maintenance projects in
 previous cases.

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If you have any questions concerning this letter, please contact Jim Little at (404) 562-9118.

Sincerely,

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides, and Toxics
Management Division

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors))
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)))
Defendants.	ý)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-J



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY REGION 10 1200 Sbith Avenue Seattle, Washington 98101

Reply To Ann Of: OAQ-107 NOV 0 5 2001

Alan Newman
State of Washington Department of Ecology
300 Desmond Drive SE
P.O. Box 47600
Olympia, Washington 98504-7600

Re: Response to Inquiry Regarding Routine Maintenance, Repair and Replacement Analysis for Recovery Purnace Modifications at Longview Fibre, Longview Mill and Boise Cascade Corporation, Wallula Mill

Dear Mr. Newman:

This letter responds to your December 13, 2000, letter to Dan Meyer of my staff. You requested that the United States Environmental Protection Agency, Region 10 (Agency or EPA) concur with two preliminary Prevention of Significant Deterioration of Air Quality (PSD) applicability interpretations made by the State of Washington Department of Ecology (Ecology). Although not specifically mentioned in the December 13th letter, EPA learned through subsequent discussions with Ecology that the two facilities discussed in the letter are the Longview Fibre pulp and paper mill located in Longview, Washington, and the Boise Cascade pulp and paper mill located in Walhula, Washington. We also learned that Boise Cascade had already undertaken the activity in question by December 2000, while Longview Fibre has applied for a PSD permit.

In each case, the threshold question is whether the activity is a "physical change." If it is a physical change, further analysis would be required to determine whether there would be a resultant significant net emissions increase. Because no information was provided related to emissions increases, EPA expresses no opinion with respect to that issue in this letter.

Regarding whether the activities in question are or would be physical changes, both sources asked Ecology to consider whether the activities fall within the exclusion from the definition of physical change for routine maintenance, repair and replacement under 40 C.F.R. § 52.21(b)(2)(iii)(a). In analyzing whether these changes are subject to this exemption, we note that the September 9, 1988 Memorandum from Don R. Clay, Acting Assistant Administrator for Air and Radiation to David A. Kee, Director, Air and Radiation Division, Region V (Clay Memorandum) at page three, states that the clear intent of the PSD regulations is to construe "physical change" very broadly, to cover virtually any significant alteration to an existing plant and to interpret the exclusion related to routine maintenance, repair and replacement narrowly.



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Ecology has already instructed Longview Fibre to apply for a PSD permit based on Ecology's conclusion that the proposal to completely reconstruct the firebox in Recovery Furnace No. 19 (RF 19) is a physical change that is not routine, and that the change would result in a

significant net emissions increase. Based on the information provided in your letter, EPA has no reason to disagree with Ecology's assessment that the physical change to RF 19 at Longview Fibre was not routine.

In your December 13, 2000, letter, you state that Ecology's preliminary conclusion was that Boise Cascade's Recovery Furnace No. 2 (RF 2) tube replacement project constitutes routine maintenance, repair or replacement, and thus does not require a PSD permit. Based on the information currently available to the Agency, EPA does not concur with Ecology's assessment of Boise Cascade's RF 2 tube replacement project. For the reasons discussed below, EPA believes that when all the factors used to assess whether a project constitutes routine maintenance, repair or replacement are considered together, the information provided to the Agency does not support the conclusion that the RF 2 tube replacement project was "routine."

Background

RF 2 was originally constructed in the 1960's as a power boiler. In 1980 the power boiler was significantly modified and converted into a recovery furnace. Boise Cascade obtained a PSD permit for this modification. RF 2 experienced an emergency shutdown in May 2000, after a water leak was discovered in one or more boiler tubes. During the shutdown, an inspection revealed cracks in boiler tubes entering the steam drum. In response, the suspect tubes were plugged and RF 2 returned to service. However, Boise Cascade's insurance carrier requested a follow-up inspection. The follow-up inspection, conducted in August 2000, revealed cracks in twelve additional boiler tubes, stress cracks in the economizer, and signs of failure in the steam generator bank tubes. The insurance carrier recommended that the economizer and generator bank tubes should be replaced in order to assure continued safe and efficient operation.

In response to the insurance carrier's recommendations, Boise Cascade replaced several damaged boiler components. Prior to the repair project, RF 2 was operating at its full rated capacity in terms of both black liquor firing rate and steam production. The project was designed to safely return RF 2 to full use. The components were replaced over a three-week period during the scheduled October 1, 2000 annual maintenance shutdown. Other maintenance activity at other units throughout the mill was completed within two weeks. Boise Cascade spent \$3.9 million to return RF 2 back to service. The cost to replace RF 2 today is estimated in your letter to be \$45 to \$50 million.

Discussion

When assessing whether changes can be considered "routine" under PSD regulations, permitting authorities consider the following factors: nature and extent, purpose, frequency, and

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cost.¹ None of these factors on its own conclusively determines a project to be routine or not. Rather, all the factors and their relationship to one another are considered together. In your December 13, 2000, letter, you explain that Ecology considered all these factors and concluded that the RF2 project can be considered routine within the meaning of 40 C.F.R. § 52.21(b)(2)(iii)(a). However, based on the information provided to the Agency, EPA does not agree with this conclusion.

EPA's opinion on the proposed RF-2 tube replacement project based on the facts provided by your letter and subsequent conversations is as follows:

- Nature and Extent All economizer and generator bank tubes have been replaced. Although the replacement tubes represent less than half of total boiler tube area, they also represent complete replacement of all the tubes in two major components of the boiler. It is our understanding that such a wholesale change to a major component of RF 2 does not occur annually, or on any regular basis. This is not a matter of merely replacing only a few worm or damaged tubes on an as-needed basis. The fact that it took three weeks to accomplish the on-site work is significant because it extends beyond the mill's typical two-week outage for annual maintenance. These facts indicate that the complete replacement of all the tubes in major components is not routine.
- Purpose As you indicated in your letter, the repair to RF 2 was of an emergency nature, and hardly routine. Furthermore, whether the stress cracks to RF 2 were the result of normal wear and tear on the boiler, or due to excessive use, the cracks may simply

As early as 1988, EPA articulated its position that 'in determining whether proposed work at an existing facility is 'routine,' EPA makes a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding." Clay Memorandum at 3. EPA's Environmental Appeals Board recently confirmed the application of these factors to determine whether an activity is routine in In re: Tennessee Valley Authority, CAA Docket No. 00-6, at 64-65 (EAB, Sept 5, 2000). EPA also notes the following determinations related to whether a physical change was routine with respect to modifications at other pulp and paper mills. September 24, 2001 letter from Gregg M. Worley, Chief, Air Permits Section, Air Planning Branch, EPA Region 4, to Barry R. Stephens, P.E., Tennessee Department of Environment and Conservation (concluding that \$924,500 project at the Packaging Corporation of America (PCA)'s pulp and paper mill including replacement of all tubes in a recovery boiler generating bank, and 44 tubes on an economizer did not constitute routine maintenance, repair or replacement); September 13, 2000 letter from R. Douglas Neeley, Chief, Air and Radiation Technology Branch, Air, Pesticides, and Toxics Management Division, EPA Region 4 (concluding that \$4.6 million maintenance project at PCA pulp and paper mill including partial replacement of water tubes in furnace walls, removal and replacement of outer casing, insulation and brick work in order to repair economizer, replacement of tank shell, and inspection and repair of electrostatic precinitator, air heater, liquor heater, cascade, auxiliary equipment and ductwork, did not constitute routine maintenance, repair or replacement).

indicate that the equipment was near, or had exceeded, its useful life. Although EPA recognizes that the purpose of the project was to assure continued safe operation of the boiler, and not to increase operating capacity, safety-related projects are not categorically exempt from PSD review.

- Frequency EPA is not aware of RF 2 undergoing such an extensive boiler tube replacement project since it started up as a recovery furnace in 1980, more than twenty years ago. EPA does not believe that a wholesale boiler tube replacement project is a frequent occurrence, thus, consideration of the frequency factor does not support a conclusion that the project is routine.
- Cost As previously indicated, Boise Cascade spent \$3.9 million to return RF 2 to service. A cost of nearly \$4 million is within the range of costs for projects that have been considered non-routine by EPA in other contexts. Although Boise Cascade's annual maintenance expenditures are not specified in Ecology's letter, EPA expects that this cost is substantially greater than the annual maintenance budget for the facility, given the information we have from other similar facilities across the country. Thus, this factor also does not support a conclusion that the project is routine.

Conclusion

In your December 13, 2000 letter you ask that EPA concur on Ecology's preliminary PSD applicability determinations with respect to Longview Fibre's reconstruction of its firebox in RF 19, and Boise Cascade's RF 2 Project. As stated previously, the Agency agrees with your conclusion that Longview Fibre's RF 19 project is not routine maintenance, repair or replacement. However, after applying the facts presented in your letter describing Boise Cascade's RF 2 Project to the factors used to determine whether an activity is routine maintenance, repair or replacement, we do not agree with Ecology's conclusion that such activity was routine. We would be glad to consider any further information that you would like to provide to the Agency with regard to this matter, or if you wish to discuss the issue further, please contact Dan Meyer of my staffat 206-553-4150.

Sincerely,

Doug Cole, Acting Manager Federal and Delegated Air Programs

cc: Tapas Das, Ecology
Merley McCall, Ecology
Rich Garber, Boise Cascade Corporation
Randy Sandberg, Environmental Manager, Boise Cascade Wallula Mill
Alan Whitford, Environmental Services Manager, Longview Fibre

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors)
V.)
DTE ENERGY COMPANY, and)
DETROIT EDISON COMPANY	,)
D 0 1	
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-K

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY WASHINGTON, D.C. 20459

- OCT 14 1988

THE ADMINISTRATOR

Mr. John W. Boston Vice President Wisconsin Slectric Power Company Post Office Box 2046 Milwaukee, Wisconsin 52301

-- Dear Mr. Boston:

As you requested in our meeting on September 15, 1988, I have made final determinations regarding the applicability of the Ciean Air Act's New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) requirements to the proposed life extension project at the Port Washington steam electric generating station, which is ewned and operated by Wisconsin Electric Power Company (WEPCO). For the reasons discussed below, I have determined that, as proposed, the renovations at Port Washington are subject to both PSD and MSPS requirements. However, EPA remains willing to work with you regarding methods of compliance. As we have discussed, one alternative would be to reconfigure the project such that no emissions increases would occur. My staff is ready to meet with you to discuss these matters at any time.

I. BACKGROUND

On September 12, 1988, David Ree, Director, Air and Radiation Division, EFA Region V, wrote you regarding FSD and NSFS coverage of the Fort Washington renovations. Enclosed with that letter was a memorandum dated September 9, 1988 from Don R. Clay, Acting Assistant Administrator, addressing the background of the Fort Washington project, and analyzing at some length the relevant interpretative issues. For purposes of brevity, I will not repeat that material here, but rather incorporate it by reference.

The September documents concluded that the life extension project, as proposed, likely would be subject to PSD and NSPS requirements. However, EPA also stated that final applicability determinations could not be provided at that time in the absence of certain factual information. In our subsequent meeting you requested that EPA furnish final determinations, and agreed to provide the necessary additional information. You also asked EPA to reconsider certain of the conclusions in Don Clay's memorandum. These metters are discussed below.

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II. FINAL DETERMINATIONS

Your staff has responded to our requests for additional information, and I want to thank you for WEPCO's continued cooperation in doing so. Based on this, and the other information in EPA's files, I now make the following final determinations:

- (1) The life extension project, as proposed, will render WEFCO's Port Washington plant subject to the PSD requirements of Part C of the Clean Air Act as a major modification within the meaning of the Act and the EPA regulations at 40 C.F.R. 8 52.21.
- (2) The proposed life extension project will render each of the five steam generating units at the Fort Washington plant subject to the NSFS requirements of section 111 of the Clean Air Act as a modification within the meaning of the Act and the EPA regulations at 40 C.F.R. Part 60.

In reconsidering the memorandum and letter of September 9 and 12. I have taken a careful look at the issues you raised in our meeting: whether the renovations are routine; whether EPA has treated similar projects in a different fashion; and whether there would be an emissions increase due to a physical or operational change. However, I find no reason to depart from the reasoning of the September documents. Accordingly, I conclude that WEFCO's life extension project, if carried out as proposed, will involve a substantial and non-routine renewal of the Port Washington facilities that will significantly increase both hourly maximum and annual emissions of air pollutants.

Specifically, regarding the nature of the proposed work at Port Washington, I find that these renovations constitute physical changes for PSD purposes within the meaning of 40 C.F.R. I 52.21(b)(2)(i), and physical and operational changes for NSPS purposes within the meaning of 40 C.F.R. I 60.14(a). I find further that these changes do not come within the PSD and NSPS exclusions for routine maintenance, repair, and replacement, nor the exclusions for increases in production rate or hours of operation. (See 40 C.F.R. IS 52.21(b)(2)(iii) and 60.14(e)).

Regarding the emissions changes from the life extension project, based upon the emissions data and certain factual assertions submitted by VIPCO, I find that the Port Vashington renovations will result in a significant net increase in emissions of several pollutants for PSD purposes within the meaning of 40 C.F.R. 8 52.21(b)(2)(i), (b)(3), and (b)(21). I find further that the renovations will result in an increase in the emission rate of several pollutants at each of units 1-5 for NSPS purposes within the meaning of 40 C.F.R. 8 60.14(a) and (b).

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Enclosures A and B detail the emissions changes underlying these findings for PSD and NSPS purposes. As indicated above, EPA's calculations and determinations are based on data supplied by WEPCO. We will use the data in Enclosures A and B in the event you would like to work with us to establish an acceptable arrangement for satisfying PSD and NSPS requirements through the addition or enhancement of pollution control equipment, physical expacity restrictions, or, in the case of PSD, federally enforceable limitations on potential emissions.

III. DISCUSSION

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As you requested, I have reconsidered the question of whether the physical and operational changes at Port Washington are routine, whether applying PSD and MSPS here would be inequitable in light of EPA's past treatment of renovation projects, and whether the renovations will result in emissions increases. These matters are addressed below, as is EFA's reasoning with respect to the baselines for calculating the PSD and MSPS emissions increases reflected in Enclosures A and B.

Regarding the question of routineness, the renovations involve the replacement of steam drums, air besters, and other major components that are integral to the continued operation of the source. The work will not simply maintain the facilities in their current state, but rather will significently enhance their present efficiency and capacity, and substantially extend their useful economic life. In addition, the work called for here is rarely, if ever, performed. Moreover, this work is costly, both in relative and absolute terms. Based on these and other factors, I reaffirm Don Clay's findings on the non-routine character of the Port Washington changes. The September 9 memorandum contains a complete discussion of EPA's reasoning on this issue.

On the related equity question, I find no inconsistency here with EFA's prior determinations regarding routine and non-routine changes. I note initially that PSD and NSPS applicability determinations are made on a case-by-case basis. Thus, it is very difficult to analogize to other projects, which almost inevitably present significant factual differences. Nevertheless, my staff has reviewed the additional material you submitted on September 19, and September 27, 1988 regarding certain other renovation projects, and has informally surveyed EFA Regional Offices and state agencies.

I have concluded that none of the four steam drum replacements identified in your September 19 submission are sufficiently similar to the Port Washington project to support determinations of nonapplicability in this matter. The Carolina

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Power and Light case involved a faulty steam drum replaced prior to the initial start-up of a new unit, and would not have increased emissions for PSD or NSPS purposes. The Great Western Sugar example did not involve a utility boiler, and was too small to be affected by NSPS. The Ashland Oil facility was not at a utility, involved a waste heat boiler that was not fossil-fuel fired, and hence, was not an emissions unit subject to PSD or NSPS. The Algona Steel Co. facility was not a utility boiler, and not located in the United States.

In addition, the informal survey conducted by the Office of Air and Radiation disclosed no closely analogous cases that were ever reviewed by EPA headquarters for purposes of PSD or NEPS applicability. In particular, EPA found no examples of Steam drum replacement at aged electric generating facilities. Horeover, EPA could find no examples in which the Agency had analyzed and issued an applicability determination for a "life extension project" for any category of major source. Regarding the four utility projects identified in your September 27 submission, I note that they do not involve steam drum replacement. In addition, permit applications were not submitted to the state agencies for the Duke Power and Texas Utilities projects you cite. Consequently, they were not reviewed by any air pollution control agency. The Cincinnati Gas and Electric project was reviewed by the state, but not EPA. The state determined, and EPA Region II concurred, that the Hydraco Enterprises project was not subject to PSD based on a net decrease in emissions of all pollutents. Our informal survey and review of the projects you identified reveal that major construction activities undertaken by utilities that may be subject to Clean Air Act requirements have not been brought to the attention of EPA. The Agency is considering what steps may be necessary to address this situation.

EPA has discovered only two state agency determinations addressing life extension questions in a manner possibly inconsistent with EPA's analysis of the Port Mashington project. These instances, which apparently were not brought to EPA's attention prior to the states' determination, do not create an inequity that would justify a different conclusion by EFA in this case.

As to the question of emissions increases at Fort Washington, I believe that IPA has properly interpreted the FSD and MSPS regulations as applying to increases in emissions due to increases in hours of operation or production rate, where, as here, such operational or production increases are closely related to physical or operational changes. A contrary interpretation would allow even massive emissions increases stemming from significant new capital investment —— as distinguished from routine fluctuations in the business cycle ——

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to escape scrutiny under the Clean Air Act simply because the new investment did not involve an inherently more polluting production process. I do not believe that Congress intended such a result.

I would like to point out that the figures on emissions increases in Enclosures A and B reflect my conclusions regarding the proper points in time from which to calculate emissions changes. For PSD, I have determined under 40 C.F.R. å 52.21(b) (21) (11) that the two-year period of 1983 and 1984 -- prior to the source curtailments due to discovery of cracks in the rear steam drums — are more representative of normal source operations than the most recent two-year period. This conclusion is appropriate in light of WEPCO's historical operations.

under that program. Rather, under the circumstances presented by this case, the baseline emission rates for units 1-5 are determined by hourly maximum capacity just prior to the renovations. At this time, EPA is relying on the actual operating data you submitted to determine current maximum capacity. Although EFA is certainly open to further discussion on this point, the information contained in your September 27 and October 11, 1988 submissions is inadequate to support WEFCO's assertions that higher-than-actual capacities could be achieved on an economically sustainable basis. For example, you indicate that operation at higher levels at units 1-4 "could increase equipment deterioration thus causing further damage." Regarding Unit 5, you state that "safety concerns" dictated the decision to shut down that unit. Based on this information, we are unable to rely on WEFCO's statements as to maximum "achievable" capacity in determining the emissions changes at each of these units. Thus, for example, in the case of unit 5, the current capacity must be regarded as zero.

IV. CONCLUSION

In edopting the PSD and NSPS programs, Congress intended to address the type of long-term capital investments in pollution-emitting facilities at issue in the Port Washington life extension project. Thus, as proposed, these renovations would be subject to the requirements of both programs. However, as indicated above, my staff remains ready to work closely with WEPCO to discuss specific pollution control equipment and permitting measures that would minimize the cost to WEPCO of complying with the requirements of the Clean Air Act. I have asked Don Clay to work with you in seeking a final resolution of the compliance issues by December 1.

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Again, thank you for your cooperation in this matter.

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Lee M. Thoma

Enclosures

cc: Senator Robert W. Rasten, Jr.
Representative F. James Sensenbrenner, Jr.
Don Clay, EPA (ANR-645)
David Ree, Air & Radiation Div., Region Y

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Inclosure A

PSD Applicability

Port Washington Power Plant Renovation Project (all emissions calculations are in tons per year)

•	Actual Emissions	Potential	Net Emissions	PSD	Subjec to, PSD
Pollutant	Baseline (1)	Emissions (2)	Increase	Level	Review
Total suspende particulate	d 170	283 (3)	108	25	yes .
Sulfur dioxide	24,236	52,621 (3)	38,385	40	748
Nitrogen oxide	6 2,991	8,201	5,210	40	yes
Carbon monoxid	n - 344	397	253	100	yes
Hydrocarbon	.17	47 .	20	40	no .
Beryllium	0.0016	0.005	0,0034	0.0004	yes
Fluorides	38	98	60	3	yes.

NOTE: PSD applicability for the other PSD regulated pollutants listed at 40 CFR Section 52.21 (b) (23) (i) and (ii) has not been determined at this time.

- 1) Average emissions for two-year period defined by calendar years 1983 and 1984.
- 2) As calculated by WZPCO based on 1992 coal type, actual emissions after ZSP, and an annual capacity utilization factor of 90%.
- 3) An EPA estimate of potential emissions, based on existing federally enforceable limits (i.e., applicable SIP), may be higher. The indicated PSD applicability determination would, however, not change.

Enclosure B

NSPS Applicability Port Washington Power Plant Renovation Project

FULL LOAD EMISSIONS AT CURRENT CAPACITY (BEFORE RENOVATION)

•	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-5
SO2 (LBS/HR)	1417	1828	2043	1580	-0-
PM (LBS/HR)	15	16	12	12	-0-
NOx (LBS/HR)	480	352	2.89	221	-0-

FULL LOAD EMISSIONS AT FUTURE CAPACITY (AFTER RENOVATION)

•	UNIT-1	ONIT-2	UNIT-3	UNIT-4	UNIT-5
SO2 (LES/ECR)	2046	2037	2088	2269	2695
PH (LBS/HR)	16	16	12	17	. 15
NOX (LBS/RR)	696	392	297	316	369

SUBJECT TO NSPS (AFTER RENOVATION)

. •	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-S
502 (LBS/HR)	TES(a)	YES(a)	YES(a)	YES(a)	YES
PH (LBS/HR)	YES(b)	100	MO	YES(b)	YES
NOx (LBS/HR)	YES(c)	YES(c)	YES(C)	YES(c)	YES(C)

Notes:

- (a) With less add-on control than NSPS requirement, emissions (lb/hr) would not increase and NSPS would not apply.
- (b) Because of planned ESP upgrade, PM emissions (lb/MM Btu) after renovation are expected to be less than NSPS requirement. However, NSPS would require CEMS for opacity.
- (c) Because arch-fired boilers are used at Port Washington, current NOx emissions (1b/MM Btu) are expected to be less than NSPS requirements. However, NSPS would require a CEMS for NOx.

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)	
)	Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)	
COUNCIL, and SIERRA CLUB)	Magistrate Judge R. Steven Whalen
) Plaintiff-Intervenors)	
v.	
) DTE ENERGY COMPANY, and)	
DETROIT EDISON COMPANY)	
)	
Defendants.	

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 3-L

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

FEB 15 1989

Mr. John W. Boston Vice President Wisconsin Electric Power Company Post Office Box 2046 Milwaukee, Wisconsin 52301

Dear Mr. Boston:

This is a revised final determination, on reconsideration, regarding the applicability of the Clean Air Act's New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) provisions to the proposed life extension project at the Port Washington steam electric generating station, which is owned and operated by Wisconsin Electric Power Company (WEPCO). This determination supplements the determination set forth in an October 14, 1988 letter to you from Lee M. Thomas, which in turn incorporated my September 9, 1988 memorandum. I find it necessary to reconsider EPA's original determination and issue this revised determination in part to address matters raised by, and new information submitted by, WEPCO representatives since the October 10 letter. WEPCO believes that these new aspects call into question the accuracy of EPA's prior determination.

For the following reasons, EPA today reaffirms, with limited exceptions detailed below, its earlier findings regarding the Port Washington life extension project. I hereby incorporate by reference the October 14 letter and the September 9 memorandum, and reaffirm the findings and conclusions in those two documents except where they are specifically superseded below.

This action constitutes final agency action for purposes of judicial review under section 307(b) of the Clean Air Act, 42 U.S.C. Section 7607(b).

I. CAPITAL EXPENDITURE

EPA explained in its earlier determination that under the General Provision of the NSPS regulation, a physical or operational change which increases emissions at an affected facility is a modification subject to NSPS. See 40 CFR 60.14(a). However, 40 CFR 60.14(e) provides certain exceptions to that general rule. In particular, section 60.14(e) (2) provided that an increase in production rate at an affected facility would not, by itself, be considered a modification if that increase is accomplished without a capital expenditure.

As has been discussed in recent meetings between WEPCO and EPA, the October 14, 1988 letter from Lee M. Thomas was based in part on information



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supplied by WEPCO in a letter dated October 11, 1988 which indicated that the increase in production rate at each of the five units would be accomplished with a capital expenditure. On October 13, 1988, and November 22, 1988 WEPCO submitted revised capital expenditure calculations. EPA has carefully reconsidered its earlier determination based on those two additional submissions(see Footnote 1). However, as explained below, they provide no grounds on which to alter EPA's earlier finding on capital expenditure.

The modification provisions are designed in part to subject to NSPS those emissions increases caused by an increase in production rate that is in turn attributable to a significant investment in improvements to the capital stock. Consistent with this intent, capital expenditure calculations employ the total, as opposed to annual, cost of a given project at each affected facility.

Thus, the December 16, 1975 preamble to the promulgated definition of capital expenditure states that "the total cost of increasing the production or operating rate must be determined. All expenditures necessary to increasing the facility's operating rate must be included in this total" (40 FR 58416) (emphasis added). The total cost of the planned work at each facility is then compared to the product of the existing facility's basis and the annual asset guideline repair allowance percentage used by the Internal Revenue Service for taxation purposes. If the total project cost for each facility exceeds the product of the basis and repair percentage for each facility, there is a capital expenditure at that facility. See 40 CFR 60.2.

It is appropriate to accumulate, for capital expenditure purposes, the cost of the renovations necessary to increase the facility's production rate, because the overall work necessary to increase a facility's production rate pursuant to a particular renovation project is the same whether the work is performed in one calendar year or during two (or more) years. The use of annual costs could encourage sources to distort normal business planning by artificially stretching out costs over time as a means of evading a finding of capital expenditure and consequent NSPS coverage (see Footnote 2).

⁽Footnote 1) October 13, 1988 submission was not received in time to be considered in issuing EPA's letter of October 14, 1988.

⁽Footnote 2) Indeed, it appears that WEPCO may have extended the planned length of the Port Washington life extension project for precisely this purpose after being informed by EPA in the October 14, 1988 letter that there would be a capital expenditure using the original schedule. The unit 1 renovations have been extended from four years to five; unit 2 has been extended from four years to six; unit 3 had been extended from three years to six; unit 4 has been extended from two years to four. (Compare Telecopier Transmission, Neil Childress, WEPCO, to Gary McCutchen, EPA, October 11, 1988 (table attached to Response to Question No. 4) with Letter, Neil Childress, WEPCO, to Walt Stevenson, EPA, November 22, 1988, at page 2.)

Rather, the purpose of the exemption in 40 CFR 60.14(e) (2) is to exclude from NSPS coverage increases in production rate that are accomplished without "an expenditure for long-term additions or improvements." See 39 FR 36948 (preamble to proposed NSPS regulations). Where the economic realities of the case are that increased production and, hence, emissions, are due to normal fluctuations in the business cycle rather than a considered decision to invest in substantial capital improvements, the NSPS do not apply.

The letter submitted on October 13 from Neil Childress of your staff to Gary McCutchen of EPA presented updated basis figures (determined by multiplying the original capital investment in the facility by a coefficient representing the inflation in construction costs between the year of the investment and the year in which the capital expenditure calculation is made) for each of the emissions units at Port Washington. These figures included costs of repair or replacement of equipment, such as steam turbines, that is not part of the existing affected facility for NSPS purposes. Since applicability determinations under the NSPS modification provisions are based on the existing affected facility, capital expenditure determinations likewise are limited to costs associated with the affected facility. For NSPS Subpart Da, the affected facility is the steam generating unit as defined at 40 CFR 60.40a. Therefore, EPA staff requested WEPCO to limit the basis figures to the steam generating unit.

The November 22, 1988 letter from Neil Childress to Walt Stevenson of EPA presented revised cost figures on the renovation work on steam generating units 1 - 4 related to the capital expenditure calculations. These November 22 basis figures are understood to be limited to costs associated with the affected facility. The November 22 letter also presented a revised and extended schedule for the renovation work, under which the costs of repairs in any one year would not exceed the product of the annual asset guideline repair allowance percentage, which is 5% for electric utility steam generating units, and the basis of each unit. Mr Childress' letter concluded that since 5% of each

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unit's updated basis is not exceeded by the cost of renovation work in any one year, there would not be a capital expenditure at any of the units. The revised figures also show that the total costs for each unit over the entire renovation period would exceed the 5% basis figure by 50% to 325%.

As explained above, it is the total cost, not the annual cost of a renovation project that determines whether a capital expenditure has occurred. Accordingly, based on the calculations and total project costs in WEPCO's November 22, 1988 letter, the proposed project would result in a capital expenditure at each of the five Port Washington units, and those units would not qualify for the exemption in the NSPS modification provisions at 40 CFR 60.14(e) (2) (see Footnote 3). As to unit 5, WEPCO did not submit cost data limited to the affected facility. Thus, I have no reason to alter EPA's original determination that WEPCO has not demonstrated that the increase in production rate at unit 5 can be accomplished without a capital expenditure.

In addition, I have determined that it is more appropriate to utilize the original basis of each affected facility (as adjusted to reflect past capital improvements), expressed in nominal dollars, rather than the updated basis, expressed in current dollars, in determining NSPS applicability. Thus, even if WEPCO were correct that annual renovation costs, rather than total costs, should be used in capital expenditure calculations, in this case a comparison of annual renovation costs and the

⁽Footnote 3) WEPCO has argued that since the definition of capital expenditure at 40 CFR 60.2 refers to the IRS "annual asset guideline repair allowance percentage" (emphasis added). EPA is bound by the literal language of its own regulations to use annual rather than total project costs in making capital expenditure calculations. However, the regulations do not dictate such a result. Instead, on their face they call for a comparison between total renovation costs and the annual asset guideline. Had EPA intended the result suggested by WEPCO, it would have explicitly called for comparison of annual costs of the change for project, exceeding one year with the annual asset guideline. This it did not do. In addition, as indicated above, the purpose of the capital expenditure provision would not be served by annualizing project costs for capital expenditure purposes.

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(adjusted) original basis of each affected facility shows that a capital expenditure would still occur (see Footnote 4).

In making a more detailed inquiry into the capital expenditure matter in response to WEPCO's request, I have found that neither the NSPS General Provisions nor the preamble thereto contain any discussion of the matter of original versus updated basis, and that EPA has rarely been called upon to address this issue. However, upon review of EPA's past practice in this area, I have found that in developing performance standards for particular industries, EPA has provided the regulated community a mechanism to calculate the original basis in making capital expenditure calculations. See, e.g., "Equipment Leaks of VOC in Petroleum Refining Industry — Background Information for Promulgated Standards," EPA-450/3-81-015b, December 7, 1983 (see Footnote 5). This suggests that EPA intended the original basis to be utilized to determine whether a capital expenditure is going to be made.

Moreover, I believe that the use of original basis is consistent with the overall purpose of the NSPS modification regularions in general, and the capital expenditure provisions in particular. The effect of using original basis is that the greater the age of an affected facility, the more likely it is that a given investment resulting in increased production will be deemed a capital expenditure and trigger NSPS. This is consistent with Congress' intent in adopting new source performance standards. Older facilities are more likely to use outdated equipment which does not reduce pollution to the extent more current technology does. Congress included modified sources within the new source performance standards of section 111 to ensure the use of new technology on such sources. See CAA Sections 111(a) (2), 111(a) (4);

II. AIR HEATER RENOVATIONS AT UNIT 1

In January 1989, WEPCO asked EPA to determine whether replacement of the heat transfer surface elements on the unit 1 air heater would trigger PSD or NSPS applicability. However, in a letter dated February 3, 1989, WEPCO withdrew this request,

⁽Footnote 4) It is worth noting in this regard that if EPA were to adhere to a literal reading of IRS guidelines as urged by WEPCO, it would have no choice but to use original basis as well as annualized costs in making capital expenditure calculations for Port Washington. Using this formula, WEPCO would exceed the repair allowance percentage at units 1 - 5 for mostyears, and NSPS would still apply.

⁽Footnote 5) This Background Information Document provides an alternative to the method prescribed in the General Provision when it is difficult to determine original costs. The formula uses replacement costs and an inflation index to "approximate the original cost basis of the affected facility."

asserting that it could not receive approval in the time necessary, while reserving the right torenew it at a later time as to unit 1 or any other unit at Port Washington. Because this issue may arise again, and because I believe it bears upon the project as a whole, I find it appropriate to address the matter of air heater element replacement. Based on the information submitted regarding this new plan, as well as the earlier information submitted regarding air heater replacement work, I conclude that if WEPCO were to proceed under its revised and now withdrawn plan, it would not alter EPA's earlier finding that PSD and NSPS would apply. In order to explain this finding, it is useful to first summarize the relevant facts.

Originally, WEPCO advised EPA that it planned to replace the air heaters at units 1 - 4 in their entirety. As WEPCO explained:

Air heaters are subject to the erosive and corrosive effects of the flue gas passing through them and require regular maintenance of the heat transfer surfaces.

The plate-type air heaters on Units 1 - 4 do not lend themselves to replacement of the individual elements. Worn sections have been patched and blocked, where accessible, over the years. Now, however, overall corrosion and perforation has passed beyond the practical point of repair, and replacement of the air heaters is the economical way to maintain the air preheater system.

The air heaters on Port Washington Unit 5 and the other units on the Wisconsin Electric system [other than Port Washington units 1 - 41 are of the Ljungstrom basket design, which allows the heat transfer surfaces (baskets) to be replaced easily.

See, e.g., List of Port Washington Projects, p. 6 (Attachment to April 21, 1988 letter from John W. Boston, WEPCO, to Gary McCutchen, EPA).

On January 11, 1989, WEPCO informed the State of Wisconsin that it was considering replacing all the plate elements at unit 1. In a letter to the State of Wisconsin, WEPCO described this project as routine repair work, "necessary to halt the continuing decrease in the capability of Unit 1," and submitted a list of 40 generating units where significant portions of the air heater have been replaced. See Letter, with attachment, from Mark P. Steinberg, WEPCO, to Dale Ziege, Wisconsin Department of Natural Resources, January 11, 1989.

In a telephone conversation with EPA staff the next day, WEPCO indicated that it desired to perform the unit 1 plate replacement work during a current unit outage; that it intended to replace only half, not all, of the elements, at a cost of approximately \$500,000; that it intended to later scrap this work and replace the entire air heater as described in the original scope of work, at a cost of \$2,600,000; and that it was considering performing the same work at unit 4 also. See Record of Telephone Conversation between David Schulz, EPA, and Mark Steinberg, Neil Childress, and Walter Woelfle, WEPCO, January 12, 1989.

In a meeting on January 17, 1989, WEPCO related that if it eplaced half of the plate elements now, it probably would replace the remainder as part of the total renovation project at a later date and not replace the air heater in whole. WEPCO also related that complete replacement of the plate elements should increase unit 1's capability to the original design capacity. Finally, WEPCO stated in response to questions from EPA staff that none of the air heaters or plate elements at units 1 - 4 had ever been replaced in the past. See Memorandum, Meeting with WEPCO regarding the Port Washington Generating Station, from David Schulz, EPA, to Files, January 27, 1989.

In addition to the above information, I note that WEPCO's list of 40 units at which air heater element replacements have occurred include no units containing plate elements such as those on units 1 - 4 at Port Washington. Instead, all of the examples submitted are of the Ljungstrom basket type or the tubular type. I conclude that those examples are too dissimilar to the plate-type elements in use at units 1 - 4 to support WEPCO's contention that the work in question is routine (see Footnote 6).

Based on all of the foregoing, I find no reason to depart from EPA's earlier conclusion that PSD and NSPS would apply to the air heater work on unit 1. It appears that despite WEPCO's recent recharacterization of this work as a separate project, it in properly viewed as an integral part of the overall Port Washington life extension project. WEPCO cannot evade PSD and NSPS applicability by carving out, and seeking separate treatment of, significant portions of an otherwise integrated renovation program. Such piecemeal actions, if allowed to go unchallenged, could readily eviscerate the clear intent of the Clean Air Act's

⁽Footnote 6) Further, even the list of air heater replacement work submitted by WEPCO did not establish this as routine repair work. Those 40 units comprise only a small fraction of total operating utility units, and even at the 40 units, air heater repair or replacement appears to have been a one-time occurrence, not routine repair.

new source provisions. Accordingly, if seen as part of WEPCO's previously proposed renovation project, the recent recharacterization of the unit 1 air heater work does nothing to alter the factors determinative of PSD and NSPS coverage.

III. CAPACITY TESTING FOR UNITS 1 - 4

A. Impact of Test Results on NSPS Applicability:

In Lee Thomas' October 14, 1988 letter, EPA stated that baseline emissions for NSPS purposes are determined by hourly maximum capacity just prior to the renovations. EPA relied on actual operating data to determine that current maximum capacity at units 1 - 4 has significantly deteriorated, such that the restoration of original design capacity through the life extension project would result in corresponding emissions increases. As to unit 5, EPA stated that current capacity at unit 5 is zero because it is physically inoperable. EPA rejected WEPCO's unsupported assertions that all five units could be operated at high capacities, but held open the possibility of further discussions on that point. Subsequently, in November and December of 1988, following discussions with EPA, WEPCO conducted capacity tests to determine current actual capacity.

Based on its review and analysis of the test data, EPA finds that the tests adequately demonstrate that units 2 and 3 can be operated at their original design capacity on a sustained basis. Accordingly, I hereby supersede EPA's earlier determination and find that NSPS would not apply to units 2 and 3 by virtue of the proposed renovations so long as the capacity of these units after completion of the work is no higher than demonstrated in the recent tests (694,000 and 690,000 pounds of steam per hour, respectively). As discussed in more detail below, this revised NSPS determination does not affect our determination that the PSD provisions would be applicable to the proposed work on these two units.

During the tests on units 1 and 4, WEPCO was able to operate these units at 497,000 and 586,000 pounds of steam per hour, respectively, representing 72% and 89% of these units' respective original design capacities. These tests are adequate to confirm EPA's original determination that units 1 and 4 are not capable of operating at their original design capacities, and that restoration of the lost capacity through the life extension will trigger NSPS coverage. EPA today also determines that these tests are not adequate to show that current actual capacity for purposes of establishing the NSPS baseline is as high as the levels achieved during the recent tests. Rather, I reaffirm that baseline for those units is determined by the lower capacities reflected in recent actual operating data as set forth in Lee Thomas' October 14 letter. EPA must reject the tests for purposes of establishing

actual NSPS baselines because during the testing discussed above, there were significant, measured exceedances of the applicable particulate mass emission limit, and several measured exceedances of the applicable opacity limit contained in the Wisconsin State Implementation Plan. One of the purposes of these tests was to determine the maximum actual capacity of the Port Washington units that can be achieved in a lawful manner. As a consequence of the measured exceedances, WEPCO's tests cannot be relied on to demonstrate that the company could lawfully sustain the levels achieved during the testing.

Regarding unit 5, I find that by declining to conduct or schedule capacity tests, WEPCO has effectively conceded that unit 5 is at present inoperable. Therefore, I reaffirm that its baseline for NSPS purposes is zero.

B. Impact of Test Results on PSD Applicability.

In its February 3, 1989 letter, WEPCO asserted that EPA's October 14, 1988 determination assumed that the emission rate of each unit would increase following the renovations. Thus, WEPCO claims, EPA did not address the question whether units that are not increasing their emission rates following renovation can be deemed to trigger PSD. WEPCO is incorrect on both counts.

EPA's prior determination explained that under the PSD program, unlike NSPS, baseline emissions are determined by representative actual emissions prior to the physical or operational change. Accordingly, the results of testing conducted by WEPCO, intended to determine current maximum hourly capacity, have no impact on the existence of a significant net emissions increase for PSD purposes. Hence, those test results provide no reason to alter EPA's prior determination regarding PSD applicability.

Actual emissions are the product of the emission rate (amount of pollution per unit of production or throughput, e.g., pounds of sulfur dioxide per ton of coal combusted), the production rate or capacity utilization (amount of production or throughput per hour, e.g., tons of coal combusted per hour), and the hours of operation (e.g., hours per year). In its prior determination, EPA explained that an increase in any one of these three factors, if attributable to a physical or operational change, can trigger an emissions increase for PSD purposes, and rejected WEPCO's contention that only increases in the emission rate were determinative. In so doing, EPA explicitly assumed that emissions increases at Port Washington would come not from an increase in emission rate, but rather from increases in production rate or hours of operation. Sec Memorandum from Don R. Clay, September 9, 1988 at 8.

WEPCO further implies in its February 3, 1989 letter that the demonstration that units 2 and 3 can operate now at maximum design capacity means that there will be no increase in production rate for PSD purposes following the renovations. This is not the case because PSD baseline emissions are determined by representative actual emission rate, production rate, and hours of operation prior to the physical change. Representative actual emissions are determined by examining the actual emissions during a representative two year period, (See 40 CFR 52.21(b) (21) (ii)) which in this case the Administrator determined to be 1983 and 1984 (See Lee Thomas' Oct. 14 letter, at 5). The hourly capacity demonstration for NSPS purposes is not relevant to the PSD analysis.

IV. NSPS OPERATIONAL LIMITATIONS

In my September 9, 1988 memorandum, I pointed out that an affected facility cannot avoid NSPS applicability by offsetting, through the use of fuel with a lower sulfur content, an increase in the emission rate that would otherwise occur due to a physical or operational change. As I explained at that time, 40 CFR 60.14(e) provides that use of an alternative fuel or raw material — such as higher-sulfur coal — which an existing facility was designed to accommodate before a physical or operational change does not constitute a modification for NSPS purposes. It follows that the facility cannot avoid NSPS by switching to lower-sulfur fuel to counteract a prospective increase in emission rate because, under the regulations, the facility would always have to option to switch back to a higher-sulfur fuel at a later date without triggering NSPS.

Subsequent to the issuance of EPA's October 14, 1988 letter, WEPCO inquired whether it might be able to utilize lower-sulfur coal to avoid NSPS at Port Washington, notwithstanding the regulatory provision explained above, by agreeing to federally enforceable permit conditions that would bar the company from switching back to higher sulfur coal in the future. Restrictions of this nature are acceptable for netting transactions under the Act's PSD provisions. However, the statute reflects a basic political decision that fossil fuel-fired sources not rely only on natural occurring less-polluting fuels to comply with the NSPS. Instead, Congress declared that compliance must depend in part upon the application of flue gas treatment or other pollution control technologies. Thus, section 111(a) (1) (A) (ii) defines "standard of performance" for fossil fuel-fired sources as requiring the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of

fuels which are not subject to treatment prior to combustion. Congress further clarified this point in a later paragraph of section 111(a) by adding:

For the purpose of subparagraph (1) (A) (ii), any cleaning of the fuel or reduction in the pollution characteristics of the fuel after extraction and prior to combustion may be credited ... to a source which burns such fuel.

This core policy judgment is reflected as well in the legislative history of the 1977 Clean Air Act amendments. For example, the Conference Report states:

The Senate concurs in the House provision with minor amendments. The agreement requires (1) that the standards of performance for fossil fuel-fired boilers be substantially upgraded to require the use of the best technological system of continuous emission reduction and to preclude use of untreated low sulfur coal alone as a means of compliance; ... (3) that for fossil fuel-fired sources, the new source performance standards must be comprised of both a standard of performance for emissions and an enforceable requirement for a percentage reduction in pollution from untreated fuel.

H.R. Rep. No. 95-564, 95th Cong., 1st Sess. 130.

Because the will of Congress is so clear that lower-sulfur fuels alone will not suffice to comply with NSPS, it would be inconsistent with the legislative intent for EPA to allow sources to use lower-sulfur fuel to avoid coverage of NSPS in the first instance in the manner suggested by WEPCO. If EPA were to follow such a course, numerous modifications to existing facilities could escape coverage in a manner contrary to the statutory purpose.

V. THE TIMING OF THE LIFE EXTENSION PROJECT

In discussions with EPA. WEPCO has challenged, on grounds of timing, EPA's position on baseline emissions for NSPS purposes. In its prior determination, EPA explained that under the NSPS regulations, baseline emissions are determined by hourly maximum capacity just prior to the renovations. Thus, the baseline for unit 5 at Port Washington is zero because the unit has been shut down for several years due to safety concerns. In response,

WEPCO has presented the hypothetical question whether EPA would still have found a zero baseline if unit 5 had been shut down on a Friday due to some unexpected or catastrophic failure of a major component previously in good working order, and WEPCO had sought to replace that component on the following Monday. WEPCO asserts that in such circumstances. EPA should have established baseline emissions using the emissions rate just prior to the breakdown.

I find it unnecessary to engage in speculation by addressing the hypothetical situation presented by WEPCO, because it is far removed from the true circumstances surrounding the proposed Port Washington life extension project. In fact, unit 5 has been shut down for over four years, not a weekend, and that is the foundation of EPA's analysis and determination.

In conclusion, with limited exceptions, EPA today reaffirms the decisions reached in the October 14 determination. In addition, EPA has concluded that the work on each unit constitutes a capital expenditure and that the proposed air heater plate replacement work on unit 1 would trigger PSD and NSPS. As a result of the capacity test demonstration, however, 1 find that units 2 and 3 at Port Washington can be operated at their design capacity on a sustained basis. Therefore EPA's earlier determination with respect to NSPS applicability is superseded and NSPS would not apply to units 2 and 3 by virtue of the proposed renovations so long as the capacity of these units after the completion of this work is no higher than demonstrated in the recent tests. This determination does not affect PSD applicability for these two units. If you should have any questions about the foregoing, please feel free to contact me. Thank you for your cooperation in this matter.

Sincerely,

Don R. Clay
Acting Assistant Administrator
for Air & Radiation

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB)) Judge Bernard A. Friedman)) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.	
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY	
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 4

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY REGIONS 77 WEST JACKSON BOULEVARD - CHICAGO, IL 60504-3590

MAY 23 2000

REPLY TO THE ATTENTION OF R-19J

Henry Nickel Counsel for the Detroit Edison Company Hunton & Williams 1900 K Street, N.W. Washington D.C. 20006-1109

Dear Mr. Nickel:

I am responding to your request on behalf of the Detroit Edison Company for an applicability determination regarding the proposed replacement and reconfiguration of the high pressure section of two steam turbines at the company's Monroe Power Plant, referred to as the Dense Pack project. Specifically, you requested that the United States Environmental Protection Agency (EPA) determine whether the Dense Pack project at the Monroe Power Plant would be considered a major modification that would subject the project to pollution control requirements under the Prevention of Significant Deterioration (PSD) program.

We have reviewed your original request, dated June 8, 1999, and the supplemental information you submitted on December 10, 1999, and March 16, 2000. We provisionally conclude that the Dense Pack project would not be a major modification. Thus, Detroit Edison may proceed with the project without first obtaining a PSD permit. Although the Dense Pack project would constitute a nonroutine physical change to the facility that might well result in a significant increase in air pollution, Detroit Edison asserts that emissions will not in fact increase due to the construction activity, and EPA has no information to dispute that assertion.

As you know, nonroutine changes of any type, purpose, or magnitude at an electric utility steam generating unit -- ranging from projects to increase production efficiency to even the complete replacement of entire major components -- are excluded from PSD coverage as long as they do not significantly increase emissions from the source. Thus, Detroit Edison has been free to proceed at any time with the Dense Pack project without first obtaining a PSD permit as long as it adheres to its stated intention to not increase emissions as a result of the project. Indeed, EPA encourages the company to proceed with the project on this basis, since it appears to both reduce emissions per unit of output and not increase actual air pollution.

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As you are also aware, under the applicable new source review regulations, in determining if a physical change will result in a significant emissions increase at an electric utility plant, companies may use an "actual" to "representative actual annual emissions" test for emissions from the electric utility steam generating unit, under which a calculation of baseline emissions and a projection of future emissions after the change is needed. Our determination of nonapplicability is provisional because Detroit Edison has not, to our knowledge, provided a calculation of baseline emissions or projected future emissions to the permitting agency, and this should be done prior to the start of construction. The basis for this determination is summarized below and is set forth in full in the enclosed detailed analysis.

In determining whether an activity triggers PSD, the Clean Air Act and EPA's regulations specify a two-step test. The first step is to determine if such activity is a physical or operational change, and if it is, the second step is to determine whether emissions will increase because of the change. The statute admits of no exception from its sweeping scope, but EPA's regulations contain some narrow exceptions to the definition of physical or operational change. In particular, Detroit Edison claims that the Dense Pack project is eligible for the exclusion for routine maintenance, repair, and replacement. The determination of whether a proposed physical change is "routine" is a case-specific determination which takes into consideration the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors. After carefully reviewing all the information you submitted in light of the relevant factors, EPA has determined that the proposed project is not "routine."

The purpose of the Dense Pack project, to significantly enhance the present efficiency of the high pressure section of the steam turbine, signifies that the project is not routine. An upgrade of this nature is markedly different from the frequent, inexpensive, necessary, and incremental maintenance and replacement of deteriorated blades that is commonly practiced in the utility industry. For instance, past blade maintenance and replacement of only the deteriorated blades at Detroit Edison has never increased efficiency over the original design. Accordingly, because increasing turbine efficiency by a total redesign of a major component is a defining feature of the proposed Dense Pack project, it clearly goes significantly beyond both historic turbine work at Detroit Edison, and what would otherwise be considered a regular, customary, or standard undertaking for the purpose of maintaining the existing steam turbine units. The project also goes well beyond routine turbine

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maintenance, repair, and replacement activities for the utility industry in general.

The nature and extent of the work in question — replacement of the entire high pressure sections of the steam turbines for Units 1 and 4 at Monroe — suggests that the Dense Pack project is not routine. It would result in greater efficiency above the level that can be reached by simply replacing deteriorated blades with ones of the same design and, in addition, will substantially increase efficiency over the original design. Specifically, the Dense Pack upgrade would not only restore the 7 percent of the efficiency rating lost over the years at each unit but would improve the unit's efficiency by an additional 5 percent over its original design capacity. Accordingly, the proposed project represents a significant and major redesign and replacement of the entire high pressure sections of the steam turbines at Units 1 and 4 at the Monroe facility.

The frequency with which utilities have undertaken turbine upgrades like the Dense Pack project also indicates the nonroutine nature of the changes. The information provided by Detroit Edison, regarding past history at the Monroe facility, describes what is characterized as necessary maintenance, repair, and replacement of deteriorated turbine blades approximately every 4 years. During these overhaul periods, it is not uncommon for the company to replace up to several turbine blades at one time. It is common among other utilities to also perform similar turbine maintenance. However, Detroit Edison has not provided any information to suggest that a complete replacement and redesign of the high pressure section of a steam turbine is conducted frequently at Monroe or at any other individual utility. Instead, Detroit Edison relies on its claim that projects "similar" to the Dense Pack project have been performed at a number of utilities. This information does not indicate that the replacement of the high pressure section of the steam turbine is frequent at the typical utility source; to the contrary, the only available information reflects that projects like the Dense Pack project have been performed only one time, if ever, at individual sources.

The cost of the Dense Pack project is significant and tends to indicate that this project is nonroutine. Detroit Edison expects the Dense Pack replacement to cost approximately \$6 million for each turbine unit, for a total of \$12 million. The EPA has rejected claims of routineness in past cases where the cost was substantially less than this figure. Moreover, Detroit Edison intends to capitalize the entire cost of this project, and EPA

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believes that a \$12 million project that is 100 percent capital improvement indicates that it is a major undertaking.

Beyond the clearly significant absolute cost of this project, available information suggests that this expenditure far exceeds the cost typically associated with turbine blade maintenance activity. Detroit Edison provided only a summary of the total project costs for past maintenance and inspections at the facility, the total costs of which ranged from less than \$1 million to a little more than \$6 million. Although Detroit Edison did not provide any detail regarding what specific activities comprise these aggregated amounts, it acknowledges that it spent only \$18,700, \$33,100, and \$7,900 to replace highpressure rotors in three turbine projects in 1981 and 1982. Further, the project is significantly more costly than simply replacing deteriorated blades today; Detroit Edison acknowledges that the Dense Pack upgrade would cost three times more than its alternative blade repair and replacement project. Accordingly, it appears that the costs associated with the Dense Pack project greatly exceed the amounts spent previously by Detroit Edison or that it would spend presently for the replacement of deteriorated turbine blades or rotors.

For the reasons delineated above, we conclude that the changes proposed by Detroit Edison are not routine. Detroit Edison's submissions do not demonstrate that projects such as the Dense Pack project are frequent, inexpensive, or done for the purpose of maintaining the facility in its present condition. Instead, the source relies on two principal arguments: (1) it claims that this project is less significant in scope than was the activity in question in the 1988 applicability determination for the Wisconsin Electric Power Company (WEPCO); and (2) it alleges that EPA has interpreted the exclusion for routine activity expansively to exempt all projects that do not increase a unit's emission rate. EPA rejects both of these arguments, the former because both EPA and the U.S. Court of Appeals for the Seventh Circuit viewed WEPCO's activity as "far from" routine and thus this attempted comparison to WEPCO is unsuitable, and the latter because it is demonstrably incorrect. The attached analysis addresses these points in significant detail.

When nonroutine physical or operational changes significantly increase emissions to the atmosphere, they are properly characterized as major modifications and are subject to the PSD program. In general, a physical change in the nature of the Dense Pack project, which provides for the more economical production of electricity, would be expected to result in the increased utilization of the affected units, and thus, increased

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emissions. Notwithstanding the fact the Monroe units may be high on the dispatch order, the Dense Pack project would allow Detroit Edison to produce electricity more cheaply per unit of output, thereby creating an incentive to run Units 1 and 4 above current levels. Even a small increase over current normal levels in the utilization of the affected units would result in a significant increase in actual emissions of criteria pollutants. For example, in 1997, at the Monroe facility Unit 1 emitted approximately 14,000 tons of nitrogen oxides $\langle NO_x \rangle$ and 41,000 tons of sulfur dioxide $\langle SO_z \rangle$, and Unit 2 emitted 12,000 tons of NO_x and 35,000 tons of SO₂. Based on this information, if a one to five percent increase in operation were to result from the Dense Pack project, increases on the order of 160-800 tons of NO_x and 400-2000 tons of SO₂ would occur.

Detroit Edison, however, maintains that emissions will not increase as a result of the Dense Pack project. Specifically, the company contends that representative actual annual emissions following the change will not be greater than its pre-change actual emissions, because the Dense Pack upgrade will not result in increased utilization of the units. As you are aware, the PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. In projecting post-change emissions, Detroit Edison does not have to include that portion of the unit's emissions which could have been accommodated before the change and is unrelated to the change, such as demand growth.

Under the WEPCO rule, Detroit Edison must compute baseline actual emissions and must project the future actual emissions from the modified unit for the 2-year period after the physical change (or another 2-year period that is more representative of normal operation in the unit's modified state). As noted above, Detroit Edison has not provided these figures to verify its projection of no increase in actual emissions, and should submit them to the Michigan Department of Environmental Quality prior to beginning construction. In addition, Detroit Edison must maintain and submit to the permitting agency on an annual basis for a period of at least 5 years (or a longer period not to exceed 10 years, if such a period is more representative of the modified unit's normal post-change operations) from the date the units at the Monroe Plant resume regular operation, information demonstrating that the renovation did not result in a significant emissions

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increase. If Detroit Edison fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the Dense Pack project.

Finally, regardless of whether PSD review is triggered due to the Dense Pack project, Detroit Edison must meet all other applicable federal, state, and local air pollution requirements.

This determination will be final in 30 days unless, during that time, Detroit Edison seeks to confer with or appeal to the Administrator or her designee regarding it. If you have any questions regarding this determination, please contact Laura Hartman, Environmental Engineer, at (312) 353-5703, or Jane Woolums, Associate Regional Counsel, at (312) 886-6720.

Sincerely,

/8/ original signed by Francis X. Lyons

Francis X. Lyons Regional Administrator

Enclosure

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cc: Peter Marquardt, Esq., Special Counsel Detroit Edison Company 2000 Second Avenue - 688 WCB Detroit, Michigan 48336

> Russell Harding, Director Michigan Department of Environmental Quality

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DETROIT EDISON APPLICABILITY DETERMINATION **DETAILED ANALYSIS**

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I. Introduction

If a company intends to construct a major source or a major modification at a source, that source is required to obtain a major new source review permit before beginning construction. If a source questions whether a change is subject to major new source review, the source can request an applicability determination. In this case, Detroit Edison Company has requested an applicability determination from the United States Environmental Protection Agency (EPA). This analysis outlines EPA's decision on the applicability determination for Detroit Edison's proposed project

II. Summary of Request and Brief Conclusion

Detroit Edison Company is proposing to replace and reconfigure the high pressure portion of two steam turbines at its Monroe Power Plant. The company refers to this project as the "Dense Pack" project in general, the Dense Pack project would consist of replacing and reconfiguring all of the blades in the high-pressure section of two turbines to substantially increase plant efficiency and reduce maintenance costs. On June 8, 1999, Henry Nickel, Hunton & Williams, submitted on behalf of Detroit Edison a request that EPA determine whether the Dense Pack project would be a "major modification" to the Monroe source, subject to the Prevention of Significant Deterioration (PSD) requirements of the New Source Review (NSR) program. An activity is a major modification and requires a PSD permit if it constitutes a nonexempt physical or operational change and if it results in a significant net increase in emissions. Detroit Edison claimed that the proposed Dense Pack project at two units in Detroit Edison's Monroe Power Plant would not be a "physical change," as the PSD regulations use that term, but instead would qualify for an exemption from the definition of "physical change" under the exclusion for routine maintenance, repair, and replacement. In the alternative, Detroit Edison maintained that the change would not result in an emissions increase that would trigger PSD.

In a letter dated June 25, 1999, EPA wrote Mr. Nickel acknowledging receipt of the request. In another letter to Mr. Nickel dated July 12, 1999, EPA requested more information regarding the proposed Dense Pack project and Detroit Edison's arguments in order to proceed with the review. On December 10, 1999, Mr. Nickel submitted information in response to EPA's July 12th request. In addition, on March 16, 2000, Detroit Edison submitted another letter, along with additional supporting materials. The following summarizes EPA's review of the proposed Dense Pack project based upon these submissions.

EPA has provisionally determined that PSD would not apply at this time if Detroit Edison were to construct the Dense Pack upgrade as described. The project would entail substantial, infrequently performed, and costly construction for the purpose of increasing the source's generating capacity both beyond its prior design and its current capacity. Accordingly, EPA finds that the upgrade is a "physical change," as that term is used in the Clean Air Act (CAA) and its implementing regulations. The Agency rejects Detroit Edison's claim that the project

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qualifies for the exemption for routine maintenance, repair, and replacement, because our analysis of the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, leads us to conclude that the project is not "routine" as EPA has historically interpreted that regulatory term. In addition, because the Dense Pack project will substantially increase the operational and economic efficiency of the Monroe facility, EPA finds that the project provides an incentive to significantly increase utilization, and thus, emissions. Detroit Edison has stated, however, that emissions at the plant will not in fact increase as a result of the Dense Pack upgrade, and EPA has no specific information to dispute that assertion. Accordingly, EPA provisionally accepts Detroit Edison's assertion of no emissions increase. However, to establish that no emissions increase will result and that PSD does not apply, the regulations applicable to electric utility steam generating units call for a calculation of baseline actual emissions and a projection of future actual emissions. Thus, before beginning construction on the project, Detroit Edison should provide this calculation and projection to the permitting agency to affirm its assertion of no emissions increase.

III. Factual Background

A. Current Conditions

Detroit Edison's Monroe Power Plant contains four coal-fired boilers, along with four associated steam turbines. The turbines convert the steam generated in the boilers into electric energy, using a system of blades or buckets to convert the energy stored in the steam from the boilers into mechanical energy. This mechanical energy is then transferred to an electric generator. The Dense Pack project is being proposed for two of the four turbines, Units 1 and 4. Units 1 and 4 began operating in 1971 and 1974, respectively. Both units have nominal ratings of 750 megawatts. Currently, the units at Detroit Edison's Monroe Plant, along with those at its Belle River Power Plant, are very high in the loading order for fossil fuel generation in the Detroit Edison system. Detroit Edison claims that, as a result, it has operated Units 1 and 4 at or near maximum capacity over the past five years. Specifically, between 1995 and 1998, the capacity factors for Unit 1 and Unit 4 have been 82.8%, 62.7%, 87.8%, 83.5%, and 63.0%, 82.2%, 79.6%, 87.4%, respectively.

According to submitted information, Detroit Edison shuts down the electric generating units and performs inspections approximately every four years. In addition to other work on other portions of the facility, Detroit Edison performs necessary maintenance, repair, and replacement of individual deteriorated turbine blades at that time. Historically, the source has not had to repair or replace blades in the high pressure section of the turbines every time it inspected them, but such maintenance, including piecemeal repair or replacement, occurs periodically. Detroit Edison states that these scheduled outages typically last a minimum of six weeks, but does not specify how much of this time is devoted to the repair and replacement of worn blades. In general, repair or replacement of the turbine blades could be to maintain fuel efficiency, reliability, safety, or generating capacity, or to comply with regulatory requirements, insurance company requirements, corporate practices, or other reasons. It appears from

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individual inspection reports that maintaining efficiency was the stated reason for most inspections and maintenance.

According to Detroit Edison, the turbines at Units 1 and 4 currently are operating at 7% below their original efficiency ratings due to accumulated deterioration in the high-pressure turbine blades. Replacement of the deteriorated blades with blades of the same design would replace only 2% of the lost efficiency, leaving the units 5% below their original efficiency rating. Detroit Edison estimates the cost of replacing only the currently deteriorated blades to be approximately \$2 million per unit. Detroit Edison provided only a summary of the project costs for past maintenance and inspections at the facility, the total costs of which ranged from less than \$1 million to a little more than \$6 million. Detroit Edison spent \$18,700, \$33,100, and \$7,900 to replace high-pressure rotors in three projects in 1981 and 1982. Detroit Edison has not provided other specific cost information regarding the cost of on-site blade repair and replacement or similar information for the utility industry as a whole.

B. Proposed Dense Pack Project

Detroit Edison is proposing to replace the entire high-pressure sections of two turbines to allow for the use of a new type of turbine blade and to reconfigure the design in order to improve efficiency and reduce maintenance costs. To install the Dense Pack, Detroit Edison must shut down the units. Detroit Edison expects the installation to take approximately 44 days, and plans to complete the installation during the time normally allotted for turbine outages. Installation of the Dense Pack would involve replacement and reconfiguration of blades in the high-pressure sections of the two units, using rotors and casings to support the new blade configuration. In addition, the Dense Pack would use a newer, substantially improved type of blade than is currently in use at the Monroe facility.

As noted above, Detroit Edison states that the high pressure sections of the turbines at Units 1 and 4 are operating at 7% below their original efficiency ratings due to accumulated deterioration in the high-pressure section of the turbines. The Dense Pack project would increase efficiency of the high-pressure sections of the turbines over current levels by 12%, restoring the 7% lost efficiency at the high pressure section and improving the efficiency of the high-pressure section by 5% over the original design. This increased efficiency in the high-pressure sections would increase the overall efficiency of each of the turbines by 4.5%. In addition, the new Dense Pack configuration could reduce efficiency deterioration by 70%. Therefore, Detroit Edison expects the inspections and needed repair or replacements to occur once every 10 years, instead of once every 4 years.

Detroit Edison expects the Dense Pack project to cost approximately \$12 million. Detroit Edison plans to capitalize 100% of the cost of the Dense Pack project.

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IV. Physical Change/Change in the Method of Operation

Before providing its analysis of whether the Dense Pack project would constitute a physical or operational change, EPA believes it would be useful to review what the statute and regulations require and how they have been applied historically. Thus, the following discussion provides a context for the analysis of the project that follows.

A. Statutory and Regulatory Requirements

1. Overview

Both the CAA and the NSR regulations require a physical or operational change to occur before any particular activity is considered a "modification" which triggers new source requirements. The applicable provisions do not, however, define what constitutes a physical or operational change. EPA historically has acknowledged -- in view of these undofined broad statutory and regulatory terms -- that they could "encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a change in the way that pipe is utilized)." 57 Fed. Reg. 32314, 32316 (July 21, 1992). Recognizing that Congress did not intend everything undertaken at a stationary source to be subject to new source requirements, id., EPA has long exempted certain narrow classes of activities from being considered physical or operational changes. Accord Alabama Power Co. v. Costle, 636 F.2d 323, 400 (D.C. Cir. 1980) (although "the term 'modification' is nowhere limited to physical changes exceeding a certain magnitude," EPA possesses the authority to provide exemptions from the definition where they are of de minimis benefit or where administratively necessary). There are several such exclusions, but only one is at issue in the present case' – the exclusion for "routine"

^{1.} Detroit Edison suggests that the Dense Pack replacement project is also exempt from PSD as a pollution control project, see, e.g., 40 C.F.R § 52.21(b)(2)(iii)(h), because the source anticipates that the project will decrease the units' emissions on a per-unit-of-output basis December 10 Letter at 2: March 16 Letter at 3. This claim is not substantiated in any of Detroit Edison's correspondence with the Agency. Our analysis above accordingly focuses on Detroit Edison's primary claim - that its activity is routine. At the same time, however, EPA does not want to give the impression that it tacitly agrees with Detroit Edison's claimed exemption; to the contrary, the Dense Pack replacement project does not meet the definition of "pollution control project" in the regulations. See 40 C.F.R. §52.21(b)(2)(iii)(h), (b)(32). Moreover, virtually any major capital improvement project at an existing source is designed in part to increase efficiency of production, and this will in turn almost always have the collateral effect of reducing emissions per unit of production, even though it may provide an economic incentive to increase total production, with the net result that actual emissions of air pollution to the atmosphere could increase significantly. There is nothing in the statutory terms or structure or in EPA's regulations which suggests that such major changes should be accorded exempt status under the NSR program. To the contrary, major capital investments in industrial equipment, where they (continued...)

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activity

2. Scope of Exclusion for Routine Activity

a. Statutory and Regulatory Text

The starting point for analysis of any exemption is the language of the statute and governing regulations. Section 111(a)(4) of the CAA reads as follows:

The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

CAA § 111(a)(4). The CAA requires a PSD permit prior to "construction" of a major stationary source of any pollutant for which the area in which the source is located is designated attainment or unclassifiable, id. § 165(a), and it defines "construction" as including modifications (as defined in section 111) to existing facilities. Id. § 169(2)(C). EPA's regulations generally track the statute:

(2)(i) Major modification means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase...

E.G., 40 C.F.R. §52.21(b)(2).2 The plain language of these statutory and regulatory requirements

^{1. (...}continued) could result in an increase in emissions, appear to be precisely the type of change at an existing source that Congress intended should be subject to PSD and nonattainment area NSR permitting. See Prevention of Significant Deterioration and Nonattainment New Source Review; Proposed Rule, 61 Fed. Reg. 38250, 38262 (July 23, 1996) ("NSR Reform" proposed rulemaking). See also Puerto Rican Cement Co. v. EPA, 889 F.2d 292, 297-98 (1" Cir. 1989) (modification of emissions unit that decreases emissions per unit of output, but may result in sufficient production increase such that actual emissions will increase, is subject to PSD). Conversely, nonroutine and otherwise nonexcluded changes of any type, regardless of whether they are projects such as the Dense Pack intended to increase production efficiency, or even the complete replacement of an entire industrial plant, are excluded from PSD coverage so long as they do not result in significant emissions increases. See infra note 4.

In this determination, EPA refers interchangeably to the "PSD" and "NSR" programs.
 There are multiple sets of PSD and NSR regulations, governing the general (or "minor") program (continued...)

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2. (...continued)

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indicates their sweeping scope. Both the CAA and its implementing regulations define "modification" as including any physical or operational change. See 42 U.S.C. § 7411(a)(4), CAA § 111(a)(4); see also, e.g., 40 C.F.R. § 52.21(b)(2)(i). In light of that breadth, any regulatory exemption from the statutory and regulatory requirements should be interpreted in a limited way. See Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901, 908-09 (7th Cir. 1990) ("WEPCO") ("courts considering the modification provisions of NSPS and PSD have assumed that 'any physical change' means precisely that").

and the programs for major sources in attainment and nonattainment areas, and governing those programs where EPA is the permitting authority and those where the state is the permitting authority. For ease of use, this document refers to only the applicable requirements here, 40 C.F.R. § 52.21. Those requirements apply where, as here, the state does not have an approved PSD program in its state implementation plan and the federal PSD program regulations apply instead. See id. § 52.1180. EPA has delegated implementation of the PSD program to Michigan, which issues federal PSD permits on EPA's behalf. See id. § 52.21(u). It bears noting, however, that EPA regulations governing approved PSD programs and NSR programs for nonattainment areas also contain an identically worded exclusion for routine activity. In addition, the regulations governing EPA's new source performance standards (NSPS) contain a similar exemption for routine activity. Accordingly, the discussion below does not differentiate between

NSPS and NSR"). The most significant difference between the programs' definition of "physical change" is that the NSR regulations do not require a source to affirmatively seek an applicability determination to be exempt as a routine change, id. at 32332, but the NSPS regulations plainly do. 40 C.F.R. § 60.14(e)(1) (activity is exempt if it is "[m]aintenance, repair, and replacement which the Administrator determines to be routine for a source category"). In all respects relevant to this determination, however, the regulations are identical.

the two programs, and relies upon relevant NSPS precedents as instructive in the NSR program. Sec 57 Fed. Reg. at 32316 (noting that physical/operational change step "is largely the same for

3. There is a rule of law that exclusions from generally applicable regulations should be construed narrowly. See Auer v. Robbins, 519 U.S. 452, 462-63 (1986) (recognizing general rule of construction for regulations); see also O'Neal v. Barrow County, 980 F.2d 674, 677 (11th Cir. 1993) (where statute does not provide for exemption, regulations providing for one should be narrowly construed). Similarly, regulatory provisions should be read in conjunction with the statutes from which they are derived and with other similar provisions. Thus, just as other exclusions from the new source provisions are limited to narrow circumstances, one should read the exclusion for routine activity similarly. See, e.g., 40 C.F.R. §§ 52.21(b)(2)(iii)(b)-(e) (governing the use of alternative fuels when the source is ordered to do so pursuant to certain federal laws, when the fuel is derived from municipal solid waste, when allowed by existing permit, or when the source was capable of accommodating it before January 6, 1975 and is not prohibited from using it by a subsequent federally enforceable permit term); 52.21(b)(2)(iii)(g) (excluding changes in ownership of the stationary source).

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The requirement that a source both make a physical or operational change <u>and</u> increase emissions to be considered a modification further suggests that the physical or operational change prong of the test should be broadly construed. The statute grandfathers existing facilities from the expense of state-of-the-art controls, but not permanently. Rather, the CAA effected a balance of concerns; if plants were modified – i.e., physically or operationally changed in a manner that increased emissions – the grandfather status would be lost, and NSR would apply. The requirement that there be a net increase in emissions at a source before a modification is deemed to have occurred, however, makes the grandfather provision potentially quite broad. Indeed, this limitation on the modification rule has been viewed by EPA as open-ended – the grandfather status can be permanent so long as emissions do not increase – and environmental groups have long complained of this NSR "loophole."

It is against that statutory and regulatory backdrop that EPA adopted the exclusion for routine activity. It provides:

(iii) A physical change or change in the method of operation shall not include:

(a) Routine maintenance, repair, and replacement. . . .

40 C.F.R. § 52.21(b)(2). The text of the routineness exclusion itself conveys the narrowly limited scope of the exemption. Because the regulations provide no definition of "routine," nor does the preamble of the notice promulgating the exclusion contain a discussion that would give the exemption a particular meaning for the NSR program, the regulatory term should be used in its ordinary sense. Webster's defines "routine" as "of a commonplace or repetitious character"; "of, relating to, or being in accordance with established procedure." These definitions suggest that determining routineness appropriately involves considering whether the activity is frequent (is it "repetitious"), whether it is of significant scope (is it "commonplace"), and whether it is for a customary purpose or is being accomplished in a customary fashion (is it "in accordance with established procedure").

D. Apprecability Determinations and Other EPA Actions Constraing Routineress

In formal NSR applicability determinations, EPA has consistently interpreted the exclusion for "routine" activities narrowly. The Agency's most comprehensive discussion of the exclusion came as part of an applicability determination for WEPCO's Port Washington utility

^{4.} See, e.g., Alabama Power Co. v. Costle, 636 F.2d 323, 401 (D.C. Cir. 1979) (requiring EPA to allow replacement of depreciated capital goods without a PSD permit where no increase in emissions at the source would result, due to offsetting decreases, because "Congress wished to apply the permit process...only where industrial changes might increase pollution in an area, not where an existing plant changed its operations in ways that produced no pollution increase)"

^{5.} See, e.g., Comments of NRDC on NSR Reform proposed rulemaking (63 Fed. Reg. 39857, Notice of Availability, July 24, 1998), EPA Docket No. A-90-37, Oct. 8, 1998.

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life extension project, which was upheld by the United States Court of Appeals for the Seventh Circuit. As in the present case, EPA's analysis began with the breadth of the modification provision, turning next to "the very narrow exclusion provided in the regulations," that is, the exclusion for "routine" activity. See Memorandum from Don R. Clay, Acting Assistant Administrator for Air and Radiation, to David A. Kee, Air and Radiation Division, Region V, at 3 (Sept. 9, 1988) (Clay Memo). EPA then described the core test for meeting this exclusion: "In determining whether proposed work at an existing facility is 'routine,' EPA makes a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding." 1d. Applying these commonsense factors, the Agency concluded that the WEPCO project was "far from being a regular, customary, or standard undertaking for the purpose of maintaining the plant in its present condition." Id. 6

The WEPCO determination and subsequent court case led to significant national attention. Congressional hearings, and statutory and regulatory changes, but neither the provisions regarding routine activity nor EPA's interpretation of those provisions were affected.

Beyond the WBPCO decisions, EPA has given further guidance in other NSR and NSPS applicability determinations and related actions which elaborate on the preceding factors. For example, in a 1987 applicability determination regarding the reactivation of a roaster/leach/acid plant at the Cyprus Casa Grande Corporation's copper mining and processing facilities, EPA determined that the proposed project would constitute a "major modification," and did not fall into the "narrow and limited set of exclusions" from PSD, including the exclusion for routine activity. See Letter from David P. Howekamp, Director, Air Quality Management Division, Region IX, to Robert T. Connery, Esq., at 3-4 (Nov. 6, 1987). In particular, EPA concluded that

^{6.} Specifically, WEPCO proposed to modify its facility in a way that would replace numerous major components of the facility (including the steam drums), would require pre-approval from the state utility commission, would significantly enhance the efficiency and current production capacity of the plant and extend its useful life, would rarely be repeated during a unit's life, and would cost a substantial amount of money, over half of which was designated as capital costs. Id. at 4-6. On review, the Seventh Circuit upheld this portion of EPA's determination in its entirety. See WEPCO, 893 F.2d at 910-13.

^{7.} In addition to the guidance discussed above, EPA's narrow interpretation of the exclusion for routine activity is evident from a passage in its brief to the Seventh Circuit in WEPCO. That brief generally reiterates the points addressed in the applicability determination that was the subject of the litigation, but elaborates with a helpful example. EPA analogized industrial facilities to automobiles, emphasizing that the "regulatory exception for routine, maintenance, repair and replacement was meant to cover such things as an oil change, replacing a broken headlamp or worn-out tires, changing the sparkplugs, or other similar activities," rather than permitting the replacement of such items as the engine or transmission. Respondent's Brief at 51, WEPCO v. Reilly, 893 F.2d 901 (7th Cir. 1990) (Nos. 88-3264 & 89-1339).

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because the project called for the replacement of integral components and would entail significant time (4 months) and cost (an absolute cost of \$905,000, which constituted 10 percent of the cost of replacing the repaired unit), it was not routine. Id. at 5-6. The agency also noted that certain activities, although they would be routine "if performed regularly as part of standard maintenance procedure while the plant was functioning or in full working order," were being performed as part of an extensive rehabilitation project and, thus, were properly considered non-routine. Id. at 6; see also In re: Monroe Electric Generating Plant, Petition No. 6-99-2 at 11, 19 & n. 19 (Adm'r 1999) (in grant of CAA § 505(b)(2) veto petition, stating principle that a non-routine collection of activities, considered 'as a whole,' is not exempt under routine exclusion, even if individual activities could be characterized as routine). In another case, in 1975, EPA Region X determined that the upgrade of boilers at a pulp mill was non-routine under NSPS, in that it called for the addition of additional pressure parts previously not included in the boilers to increase the superheater surface of the boilers, even though the additional parts were contemplated under the original boiler design. Request for Ruling Regarding Modification of Weyerhaeuser's Springfield Operations, Reg. Counsel, Reg. X (Aug. 18, 1975). When reviewing whether a project was routine, other applicability determinations have considered whether the project involved: (1) the addition of certain parts previously not included in the units; (2) the expansion of parts of a unit; or (3) the replacement of an entire emissions unit. For copies of these actions and other applicability determinations and guidance documents, please see EPA's publicly-available databases, available at: http://www.epa.gov/tin; http://www.cpa.gov/region07/programs/artd/air/nsr/nsrpg.htm; and http://www.epa.gov/oeca/eptdd/adi.html, or contact the staff members named in the cover letter.

In sum, in these actions and elsewhere, EPA has assessed routineness by considering the following factors:

Nature

- Whether major components of a facility are being modified or replaced; specifically, whether the units are of considerable size, function, or importance to the operation of the facility, considering the type of industry involved
- Whether the change requires pre-approval of a state commission, in the case of utilities
- Whether the source itself has characterized the change as non-routine in any of its own documents
- Whether the change could be performed during full functioning of the facility or while it
 was in full working order
- Whether the materials, equipment and resources necessary to carry out the planned activity are already on site

Extent

- Whether an entire emissions unit will be replaced
- Whether the change will take a significant time to perform
- Whether the collection of activities, taken as a whole, constitutes a non-routine effort, notwithstanding that individual elements could be routine

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Whether the change requires the addition of parts to existing equipment

Purpose

- Whether the purpose of the effort is to extend the useful life of the unit; similarly, whether the source proposes to replace a unit at the end of its useful life
- Whether the modification will keep the unit operating in its present condition, or whether
 it will allow enhanced operation (e.g., will it permit increased capacity, operating rate,
 utilization, or fuel adaptability)

Frequency

Whether the change is performed frequently in a typical unit's life

Cost

- Whether the change will be costly, both in absolute terms and relative to the cost of replacing the unit
- Whether a significant amount of the cost of the change is included in the source's capital expenses, or whether the change can be paid for out of the operating budget (i.e., whether the costs are reasonably reflective of the costs originally projected during the source's or unit's design phase as necessary to maintain the day-to-day operation of the source)

These categories are interrelated. Many facts could be relevant to both nature and extent, while others could overlap with purpose. Moreover, none of these factors — standing alone — conclusively determines a project to be routine or not. Instead, a permitting authority should take account of how each of these factors might apply in a particular circumstance to arrive at a conclusion considering the project as a whole.

3. Analysis of Detroit Edison's Objections to EPA's Longstanding, Narrow Interpretation of the Exclusion for Routine Activity

In support of its request, Detroit Edison has submitted a number of documents in which members of the electric utility industry claim that EPA has recently changed its interpretation of the routineness exclusion by narrowing it and that EPA's prior interpretation was expansive.

See, e.g., Supplemental Comments of the Utility Air Regulatory Group, EPA Air Docket No. A-90-37 (Oct. 8, 1999) (UARG Comments). As discussed below these arguments lack merit. Moreover, it bears noting that if companies have specific questions about the scope of the exclusion, EPA has long encouraged sources to seek guidance from their permitting authorities, see New Source Review Workshop Manual at A.33-34 (Draft Oct. 1990).

^{8.} The UARG comments submitted by Detroit Edison in support of its applicability determination request pertain to the ongoing "NSR Reform" rulemaking. See 61 Fed. Reg. 38250 (1996). The views expressed here regarding the UARG Comments pertain only to this applicability determination and are without prejudice to the ultimate outcome of the pending rulemaking.

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a. Claim that Construction that Does Not Increase Unit's Emission Rate Is Routine

Among Detroit Edison's contentions is the assertion that the routine activity exclusion is properly read (and historically has been read by EPA) to cover all "capital projects to replace degraded components without increasing the design capacity or maximum achievable hourly emission rates." See UARG Comments at 43. This interpretation would leave NSR to cover only "those activities that would create 'new air pollution' by significantly increasing the pollutant emitting capabilities of the source as designed and built." Id. at 13. In essence, this argument holds that extensive construction activity at a source is exempt from new source requirements. even if actual emissions to the atmosphere increase, where the source's potential to emit does not increase. This contention does not withstand scrutiny. EPA's regulations have since 1980 explicitly required keying NSR applicability for modifications to the actual emissions consequences of a particular change. See, e.g., 40 C.F.R. §§ 52.21(b)(2)(i) (defining "major modification" as a change resulting in a significant "net emissions increase"); 52.21(b)(3)(i) (defining "net emissions increase" based on "actual emissions"); see also 45 Fed. Reg. 52676. 52700 (Aug. 7, 1980) (explaining EPA's adoption of actual emissions baseline for modifications). Industry has understood this facet of the NSR program from the outset; indeed, it was one of the central points on which industry sought review of the 1980 regulations See Brief for Industry Petitioners on Actual Emissions Definition of Net Increase, Chemical Mfrs. Ass'n v. EPA (D.C. Cir.) (No. 79-1112). Accepting Detroit Edison's proffered interpretation of the routine activity exemption, however, would moot this longstanding and contentious quarrel and would make meaningless the provisions in the regulations governing the actual emissions baseline for modifications. This runs counter to the general presumption that interpretations that render part of a regulation superfluous are to be avoided. See, e.g., U.S. v. Larson, 110 F.3d 620, 626 (8th Cir. 1997); accord WEPCO, 893 F.2d at 909 (rejecting WEPCO's proffered definition of "physical change," because it "would open vistas of indefinite immunity from the provisions of NSPS and PSD")."

b. Mary Nichols Representation that "Restoration" Activity Can Be Routine

^{9.} The argument that only changes that increase a unit's emissions rate can trigger the NSR modification provisions has been rejected by two courts of appeals. As noted, see supra note 1, in Puerto Rican Cement, the First Circuit rejected a claim that modifications to a cement kiln, which made production more efficient and decreased the hourly emissions rate but could increase the plant's utilization rate, such that actual emissions to the atmosphere might increase, were exempt from PSD. The company argued that the project fell under the PSD regulatory exclusion for changes that result in an "increase in the hours of operation or in the production rate." See 889 F.2d at 298. Similarly, in WEPCO, where the company was making "like-kind" replacements of components to restore the original design capacity of the plant, there was no increase in emissions per unit of output; rather, for PSD purposes, the emissions increase was attributable to increased utilization. The Seventh Circuit rejected the company's reliance on the exclusion for increased hours of operation/rates of production. See 893 F.2d at 916 n. 11.

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In the submitted materials, utility representatives claim that EPA has previously indicated that the utilities may undertake facility restorations without considering NSR. In 1995, industry encouraged EPA to propose to amend the NSR rules to include a "restoration" exclusion for any change that enabled a deteriorated unit to increase its emissions, as long as the unit did not exceed its highest recent (i.e., in the last 5 years) achievable capacity. EPA responded by saying that it intended to propose a number of flexible mechanisms to allow sources to make changes without triggering NSR. The Agency also said, "EPA believes that the routine maintenance exclusion already included in the existing NSR regulations also has the effect of excluding 'routine restorations.'" Letter from Mary D. Nichols, Assistant Administrator for Air and Radiation, to William R. Lewis, Morgan, Lewis and Bockius, attachment at 19 (May 31, 1995). Some in industry quarters suggest that this sentence indicates EPA's interpretation that restoration activities are, by definition, exempt. See UARG Comments at 17 ("In 1995, IEPA) confirmed that no special rule was needed for industrial 'restoration' projects because such projects were covered already under the 'routine maintenance' exclusion."). These claims are incorrect. Rather, EPA's statement says merely that "routine restorations," not all "restorations," are exempt. Thus, EPA's remark simply is tautological; it says that to the extent the restoration is itself "routine," the current exclusion for "routine" activity will exempt it from review. 10

c. Assertion that EPA Expects No Change to Trigger NSPS Modification Provision

Detroit Edison also maintains that several EPA documents indicate that the Agency believed until recently that utility modifications would generally avoid NSR, and that these documents therefore reveal an expansive understanding of the exemption for routine activity. In particular, the UARG Comments highlight a General Accounting Office (GAO) report created when Congress was considering the acid rain program, ¹¹ a letter to Senator Byrd from EPA regarding a proposed NSPS, and the preamble to the proposed NSPS. ¹² Although none of these documents discuss the scope of the routine maintenance, repair, and replacement exemption,

^{10.} For example, past piecemeal repairs and replacement of individual rotor blades at Monroe presumably restored some portion of the efficiency lost since the last scheduled outage. While not the subject of this determination, it appears that those activities — which as explained above were far different from the proposed Dense Pack upgrade — are more likely to be properly characterized as excluded "routine restorations."

^{11.} UNITED STATES GENERAL ACCOUNTING OFFICE, PUB. NO. GAO/RCED-90-200, ELECTRICITY SUPPLY: OLDER PLANTS' IMPACT ON RELIABILITY AND AIR QUALITY (1990).

^{12.} The submissions also refer to an article written by EPA staff. This document warrants no discussion; it does not represent Agency opinion, as noted in the cited article. See James DeMocker et. al, Extended Lifetimes for Coal-fired Power Plants: Effect Upon Air Quality, PUBLIC UTILITIES FORTNIGHTLY at 30 n.* (Mar. 20, 1986). Moreover, the article is silent on the question at issue here — when certain activity is routine — and therefore would not be relevant even if it did speak for EPA.

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industry points to them as evidence that EPA believed that NSR would apply to electric utilities only rarely

The cited documents do not remotely suggest a broad EPA interpretation of the routineness exemption. First, although the GAO report contains a number of statements that suggest that EPA did not expect many utilities to trigger the NSPS or PSD modification rules, it does not suggest how broadly or narrowly the exclusion for routine activity has been interpreted; further, some statements in the report are best read as reflecting a narrow scope to the exclusion. GAO Report at 28, 30 (acknowledging that "life extension projects involve physical or operational changes to power plants" and distinguishing between projects aimed at restoring generating capacity and those which prevent plant deterioration). In addition, as noted above, the PSD regulations provide broad leeway for sources to avoid new source requirements by making offsetting emissions reductions at the source even when undertaking extensive physical or operational changes that, standing alone, would result in emissions increases. In many circumstances, such "netting out" of review is a more cost-effective strategy than obtaining a PSD permit. Moreover, at the time of the 1990 CAA Amendments, any statement or assumption EPA made regarding whether electric utilities could trigger NSR was based on information provided by industry at that time. The power plant undertaking a physical or operational change is responsible for obtaining the necessary regulatory approvals from each agency that regulates it. State and federal environmental agencies do not regularly review submissions to public utility commissions, the Federal Energy Regulatory Commission, a pipeline authority or a local zoning board; nor are those agencies charged with the authority to require CAA permits. As a result, EPA as well as states, were unaware that activities that were under way at utilities would in fact increase emissions and thus trigger NSR. Although EPA's conclusions were reasonable based on the information EPA had at the time, EPA's statements might have been different based on more complete information, including information from facilities requesting applicability determinations.

Second, the utilities point to a letter to Senator Byrd from OAQPS Director John Seitz regarding potential revisions to the NSPS for steam generating units and to the preamble to a 1997 proposed rule on the same topic. Both documents indicate that EPA expected few, if any, existing units to become subject to the proposed NSPS as a result of being modified. Again, these documents do not suggest that the reason EPA had such an expectation was because of a broad interpretation of the exemption for routine activity. Indeed, the preamble to which industry refers has a lengthy discussion of the reasons why existing units would avoid the NSPS for modifications, but notably omits the "routine" exclusion. See 62 Fed. Reg. 36947, 36957 (July 9, 1997). 13

^{13.} In addition, the UARG Comments claim that a "key" factor in the D.C. Circuit's recent vacatur of the fossil-fuel boiler NSPS for modified units was that some EPA offices viewed quite a bit of "maintenance" activity as potentially covered by the modification provision and others thought that few, if any, changes would trigger the NSPS. UARG Comments at 3 n.8 (continued...)

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d. Assertion that Industry Practice Defines Routineness

The submitted materials also seem to contend that if a particular industry sector has an established practice of undertaking certain construction activity, no matter how infrequent, costly, or major, that industry practice is "routine." See UARG Comments at 37 ("[E]lectric utilities undertake maintenance, repair and replacement activities pursuant to their legal obligation to provide a safe and reliable source of electricity. This defines what is 'routine' for this industry") It is true that EPA has stated that the "determination of whether the repair or replacement of a particular item of equipment is 'routine' under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category." 57 Fed. Reg. at 32326. However, this statement merely recognizes that a piece of equipment may be more integral, costly, or less frequently replaced at one kind of facility than at another. Accordingly, although it may not be routine for one industry to replace or repair certain equipment or undertake certain maintenance activity, similar construction might be routine in a different industry. As a result, EPA has historically considered whether a typical source in the relevant industry undertakes the proposed activity as a mutine matter. See, e.g., 40 C F.R. §60.14(e)(1) (NSPS regulations require EPA determination that activity is "routine for a source category" to be exempt). This does not mean, however, that whatever activity members of a particular industry have done - no matter how infrequent, costly, sizable, or capable of expanding the source's operations or extending its useful life - is necessarily routine.

B. Analysis of "Routine" Maintenance, Repair or Replacement at the Monroe Plant

Looking at the nature, extent, purpose, frequency and cost of the project, along with other relevant factors in light of the framework discussed above, EPA concludes that the proposed Dense Pack project is a non-routine physical change. In sum, although utilities typically perform maintenance, repair and replacement of individual deteriorated turbine blades about once every four years, the reconfiguration and upgrade of a turbine's entire high-pressure section (including all of the blades) is a significant departure from necessary maintenance operations aimed at keeping the turbine in ordinary working condition, and is rarely performed at a typical utility. Detroit Edison expects the new Dense Pack configuration to substantially increase the unit's ability to convert steam to electricity over its original design and the project will reduce the rate of blade efficiency deterioration by 70%. Moreover, the new blades will alter the inspection and replacement program of worn blades, allowing inspection and replacement to occur every 10

^{13. (...}continued)
Research has revealed no support for this assertion. The court's order in the case is brief and does not suggest a reason for its disposition of the matter, except that the court believed that the NSPS for modified boilers was "seriously deficient." Lignite Energy Council v. EPA, No. 98-1525 (D.C. Cir. Sept. 21, 1999).

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years instead of 4 years. Finally, the project requires a significant capital expenditure of \$12 million, which Detroit Edison states is triple the cost of replacing the worn blades with ones of the same design, and which vastly exceeds prior blade and rotor maintenance costs. A more detailed application of the relevant factors to the information that Detroit Edison has submitted regarding the Dense Pack project follows.

Nature and Extent

Detroit Edison seeks to replace the entire high-pressure section of two turbines to allow for use of a new type of turbine blade and to reconfigure the design to improve efficiency. This includes reconfiguration of blades in the high-pressure sections of the two units, including new parts and additional stages. The turbine – in particular the high-pressure section – is an integral and major component of an electric generating facility. Furthermore, the proposed change will be of considerable importance to the operation of the facility because, among other options, it will enable the units to produce more electricity with the same coal usage, boiler heat input and steam flow, and allows operation of the units with less maintenance. In addition, by making operation of the affected units more efficient, the Dense Pack upgrade will provide an economic incentive to increase operations at the plant.

Several other facts that EPA has found telling in past decisions and guidance also indicate that the Dense Pack upgrade would not be routine. First, the project cannot be performed during the full functioning of the plant and instead would require the affected units to be shut down. Second, the project would involve the addition of parts not previously used. Third, the project could not be completed with parts typically stored on site. Finally, Detroit Edison plans to capitalize 100% of the cost of the project.

Purpose

Replacement of currently deteriorated blades with blades of the same design would restore only 2% of the efficiency that has been lost as the equipment has aged, leaving the units 5% below their original efficiency rating. The Dense Pack project, however, would increase efficiency of the high-pressure sections of the turbines over current levels by 12%, and overall efficiency of the turbines by 4.5%. The new configuration could reduce efficiency deterioration by 70%.

Thus, the Dense Pack project will not simply maintain the equipment at the current state, but will enhance the operation of the Monroe Power plant by recovering the accumulated lost efficiency, increasing the efficiency over the original design, and decreasing the rate of turbine blade deterioration in the high pressure section. This efficiency enhancement and decrease in deterioration rate would in turn substantially enhance the operational capabilities of the affected units, by providing an economic basis for increased utilization. As discussed below, Detroit Edison claims that it does not intend to use the unit more in the future as a result of the Dense Pack project, but that does not change the fact that the project would enable it to do so.

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Frequency

Turbine upgrades like the Dense Pack project are performed rarely, if ever, in the course of a utility source's life. Detroit Edison has not provided any information to suggest that individual facilities in the industry frequently conduct a complete replacement of the high pressure section of a utility steam turbine, relying instead on two claims: (1) that utilities commonly perform turbine maintenance activity; and (2) that it estimates that projects "similar" to the Dense Pack have been performed at a number of utilities. Neither of these claims addresses the central question – whether it is industry practice that a typical facility will frequently conduct the project in question. The only available information — Detroit Edison's experience — suggests that projects like the Dense Pack are performed infrequently at individual sources; this project has never been performed previously at Monroe and will greatly increase the time between "overhauls" of the high pressure section.

Cost

Detroit Edison expects the Dense Pack project to cost approximately \$12 million. Detroit Edison has estimated that replacement of the current blades with blades of the same design would cost approximately \$2 million per unit. Generally speaking, a new plant costs approximately \$2,000 per kilowatt. Therefore, a new 750 megawatt unit would cost about \$1.5 billion.

An absolute cost of \$12 million constitutes a significant cost, which tends to make this project non-routine. Detroit Edison argues that the cost of the Dense Pack project is significantly less than the cost of the Port Washington project at issue in the WEPCO case. In WEPCO, the estimated cost of the life extension project was \$87.5 million, at least \$45.6 million of which was capital costs. Clay Memo at 6. EPA acknowledges that this cost is well in excess of the proposed Dense Pack project, especially considering inflation. However, as the Agency noted in 1988, WEPCO's activity was "far from" routine, id. at 3, and the facts of that case should be considered in that context. By contrast, EPA has determined that a proposed project costing \$905,000 was non-routine. Letter from Howekamp to Connery at 5. Considering these two precedents, EPA believes that the \$12 million expenditure in this case, all of which is capital in nature, supports a determination that the proposed project is non-routine.

Although the relative cost of the Dense Pack project, when compared with replacing the entire electric generating facility, is small, it is orders of magnitude larger than other blade maintenance activity Detroit Edison has conducted in the past. For instance, it appears that the company spent \$18,700, \$33,100, and \$7,900 to replace high-pressure rotors in three projects in 1981 and 1982. Further, the project is significantly more costly than simply replacing deteriorated blades today; Detroit Edison acknowledges that the Dense Pack upgrade would cost three times more than its alternative blade repair and replacement project.

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V. Emissions Increase

Since the Dense Pack project constitutes a physical change, EPA must consider whether it would result in a significant net emissions increase. Before providing its analysis, once again EPA will review what the regulations require. Thus, the following discussion provides a context for the analysis of the project that follows

A. Regulatory Requirements

If a physical change or change in the method of operation is not "routine," it still does not trigger PSD unless it results in a significant net emissions increase. This involves comparing recent pre-change, or "baseline", actual emissions to a projection of future actual emissions following the change. A source's pre-change level of actual emissions from a given unit is "the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the [date of the change] and which is representative of normal source operation " 1d. § 52.21(b)(21)(ii). This figure must be compared to the source's post-change emissions; however, because NSR is a preconstruction program, one must project the unit's future emissions. For units that are not "electric utility steam generating units," EPA's rules require that for units that have "not begun normal operations," i.e., units that will undertake a non-excluded physical or operational change, the post-change emissions "shall equal the potential to emit of the unit," which is the "maximum capacity of a stationary source to emit a pollutant under its physical and operational design," but which also accounts for pollution controls and permit restrictions that limit lawful emissions to a level below the maximum physical capacity. Id. § 52.21(b)(4).14 If a particular change would, standing alone, increase actual emissions by more than a "significant" amount, see id. § 52.21(b)(23), the change is subject to PSD, unless other activity at the source renders the net emissions effect of the change insignificant when considered together with contemporaneous (generally within the past five years) emissions increases and decreases at the source. See id. § 52.21(h)(3) (defining "net emissions increase").

^{14.} Under current regulations, changes to a unit that are not routine nor subject to one of the other NSR exemptions are considered to be of such significance that pre-change emissions should not be relied on in projecting post-change emissions. For such units, "normal operations" refers to operations after the change, and are deemed not to have begun. The regulations initially presume that such units will operate year-round at full capacity, but a source owner is free to overcome the presumption by agreeing to limit its potential to emit to any level desired through enforceable restrictions on operations or the use of pollution controls. For example, if limiting the potential to emit results in an insignificant change in emissions, the source can avoid PSD applicability. See 63 Fed. Reg. 39858 (July 24, 1998) (Notice of Availability); see also 45 Fed. Reg. 52676, 52688-89. If business plans later change and the owner desires to relax those restrictions and obtain a PSD permit at that later time, it may do so See 45 FR 52689; 54 FR 27274, 27280.

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For electric utility steam generating units, the post-change emission increase calculation is governed by regulations adopted in 1992 (57 Fed. Reg. 32314, July 21, 1992), commonly referred to as the "WEPCO rule." Although the WEPCO rule did not change the regulatory provision that establishes a unit's pre-change emissions, EPA announced that it would view any consecutive two-year period during the preceding five years as presumptively reflective of "normal source operations" See 57 Fed. Reg. at 32324-25. In addition, EPA amended the regulations regarding a utility unit's post-change emissions in two ways. First, the rules allow utilities to project future emissions resulting from a particular change without committing to a permit restriction limiting the unit's potential to emit to a level below its maximum capacity to emit a pollutant,15 and they provide that emissions increases independent of the physical or operational change may be discounted from the post-change emissions of the unit A utility making a particular change, instead of accepting permit restrictions on the potential of the changed unit to emit a particular pollutant, may avoid PSD if its projection of "representative actual annual emissions" following the change is not significantly greater than its pre-change emissions, but only if the source "maintains and submits to the Administrator [or relevant state permitting authority] on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase." E.g., 40 C.F.R. § 52.21(b)(21)(v). Second, in evaluating the source's claimed exemption from PSD, the permitting authority must "[c]onsider all relevant information, including, but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act. ... " Id. § 52.21(b)(33)(i). The permitting authority must discount any increase "that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole." Id. § 52.21(b)(33)(ii). Nevertheless, if an emissions increase could not have occurred "but for the physical or operational change," the increase must be considered to result from the change. See 57 Fed. Reg. at 32327.

Where the end result of an emissions increase analysis for electric utilities is a projection

^{15.} We are aware, as Detroit Edison states in its initial applicability determination request, that EPA Region VII previously has suggested that a utility undertaking a change to a part of the source other than the boiler may not be entitled to take advantage of the provision that allows for a forecast of future emissions without committing to a present limitation on the source's potential to emit. We have reviewed Region VII's discussion of the matter and the applicable regulations, and we conclude that Detroit Edison may use this provision to calculate future emissions from the boilers, even though it is making changes at the turbines. The plain language of the regulation is categorical; irrespective of where a change takes place, the post-change emissions of the electric utility steam generating unit – which certainly includes the boiler – must be determined using the "representative actual annual emissions" approach. See 40 C.F.R. § 52.21(b)(21)(v).

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accepted by the permitting authority that emissions would not increase as a consequence of a particular change, the rules call for an initial determination that the change would not be a major modification subject to PSD. See Letter from David P. Howekamp, Air Division, Reg. 1X, to Richard K. McQuain, HEI Power Corp., at 1-2 (undated) (describing WEPCO rule as conferring conditional exemption from PSD where projected emissions increase is insignificant). However, if the information that the source must submit for the requisite number of years following the change demonstrates that emissions have in fact increased as a result of the change, the source becomes subject to PSD at that time. See 40 C.F.R. § 52.21(b)(21)(v); 57 Fed. Reg. at 32325 ("If ... the reviewing authority determines that the source's emissions have in fact increased significantly over baseline levels as a result of the change, the source would become subject to PSD requirements at that time.")

B. Analysis of Significant Net Emissions Increase at the Monroe Plant

Because the Dense Pack project would be a physical change to a major stationary source. Detroit Edison must estimate whether the change would result in a significant net emissions increase to determine whether it must undergo PSD review. 40 C.F.R. § 52.21(b)(2)(i). According to the submission, Detroit Edison asserts that emissions will not increase as a result of the project. As discussed below, EPA accepts for purposes of this determination Detroit Edison's representation that emissions will not increase as a result of the project, and concludes that the Dense Pack upgrade will not trigger PSD, provided that, prior to beginning construction, the company validates its representation by developing and submitting to the permitting agency a calculation of "baseline" actual emissions and a projection of future actual emissions following the project.

Detroit Edison maintains that emissions will not increase as a result of this project because it concludes that one of two consequences will follow the upgrade. First, Detroit Edison claims that because the change would increase efficiency, it would allow increased electricity generation using the same amount of coal, boiler heat input and steam flow while producing the same level of emissions as currently emitted. Alternatively, Detroit Edison claims the project would enable it to generate the same amount of electricity it currently generates using less coal, boiler heat input and steam flow, resulting in reduced emissions. Detroit Edison rejects the third possibility — that it would use the units more, and increase emissions at the plant, as a result of the blade replacement. Detroit Edison states that these units already are at the top of the loading order and had a capacity factor of approximately 85% for 1998. Thus, the company asserts, any increase in use would be the result of demand or unforeseen outages, which could and would have occurred regardless of whether or not Detroit Edison proceeds with the Dense Pack project. The company has not, however, provided any specific projections of future operations and emissions to EPA to support its claims regarding emissions levels.

EPA disagrees that the dispatch position of the Monroe plant necessarily means that the Dense Pack project would not result in increased use, and hence, increased emissions. Given the information provided by the company showing that there is some fluctuation in annual use and

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that Units 1 and 4 are not operated at their maximum physical capacity, the fact that Monroe is at the top of the loading order is insufficient to demonstrate that the significant increase in efficiency associated with the Dense Pack project, and the corresponding decrease in the cost of producing electricity, would not result in increased use and emissions. The possibility that Detroit Edison would take advantage of Monroe's increased efficiency to sell additional power in deregulated utility markets beyond its regular service area is an additional reason that the Dense Pack project may well lead to increased emissions. Accordingly, based on the information provided, EPA cannot agree at this time that any future increased emissions at the Monroe plant due to increased use should be attributed to demand growth (as that term is used in the PSD regulations) or other factors not causally related to the Dense Pack project.

EPA notes in this regard that the large size of the Monroe units means that only a small increase in use could result in emissions increases that are significant for PSD purposes. For example, if Detroit Edison decides to run the Monroe plant even 1% more due to the improved efficiency, the resulting increase in emissions would be well above the significance threshold. If a one to five percent increase in operation were to result from the Dense Pack project, increases on the order of 160-800 tons of NOx and 400-2000 tons of SO2 would occur, each of which would be considered "significant," and trigger PSD absent sufficient offsetting contemporaneous emission reductions. See 40 C.F.R. § 52.21(b)(23)(i) (defining 40 tons per year emission increases for sulfur dioxide and nitrogen oxides as "significant").

In determining whether a nonexempt physical or operational change at an electric utility steam generating unit will result in a significant net emissions increase, the applicable PSD regulations at 40 C.F.R. § 52.21(b)(21)(v) and (b)(33) call for a calculation of pre-change "baseline" actual emissions and a projection of future actual emissions for the two year period after the change (or another two year period that is more representative of normal post-change operations). Detroit Edison has not supplied such a projection, perhaps in reliance on its position that the Dense Pack project would be exempted as routine. The company has represented, however, that "the Dense Pack would not result in an increase in the number of hours these units are expected to be operated." EPA has no specific information disputing that assertion, and so is willing to accept Detroit Edison's representation. Nevertheless, until the company provides the calculation and projection called for by the regulations to verify its projection of no increase in actual emissions, our determination is provisional. Detroit Edison should submit these figures to the Michigan Department of Environmental Quality prior to the beginning of construction.

The PSD regulations also require Detroit Edison to maintain and submit to the delegated permitting agency, for a period of 5 years from the date the units resume regular operation following completion of the Dense Pack project, information demonstrating that the project did not result in an emissions increase. To adequately track post-change emissions, EPA expects that this information must include records on annual fuel use, hours of operation, and fuel sulfur content. In making these calculations, Detroit Edison may exclude emissions increases that are caused by other factors, for example, emissions increases that it demonstrates are due to variability in control technology performance or coal characteristics. In addition, when

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calculating emission increases, under current regulations Detroit Edison may exclude that portion of its emissions attributable to increased use at the unit due to the growth in electrical demand for the utility system as a whole since the baseline period. See 40 C.F.R § 52.21(b)(33)(ii)

Finally, EPA notes that regardless of whether PSD review is triggered due to the Dense Pack project, Detroit Edison remains responsible for compliance with all other applicable federal, state, and local air pollution regulations.

VI. Conclusion

For the reasons delineated above, EPA concludes that the changes proposed by Detroit Edison would not be routine. Detroit Edison's submissions do not demonstrate that projects such as the Dense Pack are frequent, inexpensive, or done for the purpose of maintaining the facility in its present condition. Therefore, the Agency determines that the Dense Pack upgrade would be a "physical change," as that term is used in the NSR regulations. EPA disagrees with Detroit Edison's claims that the Dense Pack project is eligible for the exclusion from PSD permitting for routine maintenance, repair, and replacement. The determination of whether a proposed physical change is "routine" is a case-specific determination which takes into consideration the nature, extent, purpose, frequency, cost of the work, as well as other relevant factors. After carefully reviewing all the available information, in light of the relevant factors, EPA has determined that the proposed project would not be "routine."

The PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change. Detroit Edison contends that representative actual annual emissions following the Dense Pack project will not be greater than its pre-change actual emissions, because the project will not result in increased use of the units. Therefore, Detroit Edison may avoid major PSD permitting to the extent it documents its pre-change baseline emissions and submits information following the change to confirm its pre-change projection. If Detroit Edison fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the Dense Pack project.

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)
) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE)
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
)
Plaintiff-Intervenors)
v.)
)
DTE ENERGY COMPANY, and	
DETROIT EDISON COMPANY)
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 5

Michigan New Source Review Program Review

Performed by US EPA Region 5 August 2004

- I. Executive Summary
- II. Introduction
- III. Description of MDEQ's Program
- IV. Findings
- V. Recommendations
- VI. MDEQ Concerns with the Required Program

VII. Audit Questionnaire

- 1. Common Program Requirements to PSD/NAA NSR
- 2. PSD
- 3. Nonattainment NSR
- 4. Minor NSR Programs
- 5. Public Participation
- 6. Program Staffing and Training Issues
- 7. General NSR Program Issues
- 8. Effective Construction Permits
- 9. Reform Questions

VIII. Audit Files Review

- A. Dearborn Industrial Generation
 - B. Continental Aluminum Company
 - C. Delphy Saginaw Steering System
 - D. El Paso Merchant Energy
- E. Daimler Chrysler Corporation

Appendices

APPENDIX A: ACRONYMS and DEFINITIONS
APPENDIX B: STATE and FEDERAL RULES
APPENDIX C: MEMOS, LETTERS, CHARTS
APPENDIX D: EXAMPLES of PERMITS

APPENDIX E: PROGRAM TRAINING and PUBLIC PARTICIPATION MATERIAL

I. Executive Summary

The United States Environmental Protection Agency (USEPA) performed on-site evaluations of the New Source Review (NSR) program. This is part of the NSR Program Evaluation Project. This two-day permit program review was intended to highlight the positive aspects of the state's air permitting program, and foster quality improvements for the state and federal air programs. This opportunity has not only improved our understanding of Michigan's NSR program, but also can be helpful to other permitting authorities throughout the Region and nation-wide.

In Michigan, the NSR review was conducted on July 21 and 22, 2003, concurrent with the Title V program review. The NSR review consisted of two parts: a discussion based on the New Source Reform Program Evaluation Questionnaire (VII. Audit Questionnaire), and a file review (VIII. Audit Files Review).

We found that the Michigan Department of Environmental Quality's (MDEQ) NSR program has many strengths, such as the Community Environmental Awareness Project, using several avenues to notify the public and encourage participation, providing many training opportunities for its staff, regulated entities and public, and developing areas of industry expertise. We did not evaluate the nonattainment NSR program because the entire state of Michigan had been designated attainment for all pollutants since 1999, and we agreed at the time of the audit that the state did not have to respond to that section of the questionnaire. Based on the review, we found three areas which are in need of improvement: approvability of NSR rules, synthetic minor tracking, and use of the frequency evaluation factor in a routine maintenance, repair and replacement (RMRR) exemption analysis. MDEQ is committed to working with USEPA to obtain approvable rules and to develop a tracking system for synthetic minor limitations.

II. Introduction

In 2003, as part of its oversight role, USEPA began a four-year initiative to review the implementation of the Title V and NSR permit programs by permitting authorities throughout the country. USEPA developed two questionnaires, one addressing Title V implementation and one addressing NSR, for the Regional offices to use to provide a consistent review of all of the permitting authorities. The program review questionnaires consist of two components: questions about program implementation and criteria for a file review. The purpose of the evaluation was to review the permit programs, note practices that could be helpful to other permitting authorities, document areas needing improvement, and learn how USEPA can help the permitting authority and further improve the national programs.

On July 21, 2003 through July 22, 2003, Region 5 staff visited the MDEQ offices in Lansing, Michigan. USEPA's NSR program review team

consisted of Robert Miller, Laura David, and Genevieve Damico. In addition, Mike Sewell of Office of Air Quality Planning and Standards was in attendance. We met with MDEQ management and staff by conference call to discuss the questionnaire provided prior to our visit. During the visit, we discussed the questionnaire in more detail and performed a file review according to the criteria in the questionnaire. The results of these discussions are in Part IV of this report.

This final report summarizes findings and conclusions of the USEPA Region 5 from its review of MDEQ's NSR program. The findings and conclusions in the report are based on the answers MDEQ gave to the questionnaire, the file review, and USEPA staff's knowledge of the program from experience with reviewing MDEQ permits and programs. This information was compared to the statutory and regulatory requirements for federal permitting programs.

III. Description of MDEQ's Program

The MDEQ Air Quality Division (AQD) is responsible for issuing Permits to Install (PTI) to assure that all new or modified sources of air pollution will not have a detrimental impact on human health, human welfare, or the environment, and will comply with all applicable state and federal requirements. The Natural Resources and Environmental Protection Act, Public Act 451 of 1994, as amended, Part 55 (Air Pollution Control) provides the statutory authority for the permitting program. The applicable regulation is R 336.1201 (Rule 201) of the Michigan Air Pollution Control Rules. This rule requires a person to obtain an approved Permit to Install for any potential source of air pollution unless the source is exempt from the permitting process. A summary of the PTI approval process is contained in Appendix B.

PSD

Prevention of Significant Deterioration - Michigan has no approved State Implementation Plan (SIP) for the permitting of major sources in an attainment area at this time. MDEQ implements the federal PSD program under a delegation of authority from USEPA, and follows the September 26, 1988 delegation letter for 40 C.F.R. § 52.21 (enclosed in Appendix C). At the time of the Audit, the entire State of Michigan met all National Ambient Air Quality Standards, and sources within the State were subject to the federal PSD program. However on June 15, 2004 several areas in Michigan became non-attainment for the 8-hour ozone standard (69 Fed. Reg. 23951 (April 30, 2004)).

NSR Reform

On December 31, 2002, USEPA substantially reformed the NSR program. The December regulations became effective in Michigan on March 3, 2003 through the existing PSD delegation. Michigan began implementing the reforms immediately. Although the audit questionnaire focused on

pre-reform PSD regulation implementation, the reformed PSD program was in effect in Michigan at the time of the Audit.

IV. Findings

A. Strengths

Public Involvement

Based on this review we find that the Air Quality Division is committed to work with the regulated community and general public to help maintain compliance with statutes that minimize adverse impacts on human health and the environment.

An example of the commitment by the Department to work with industries, citizens, and other states is the Community Environmental Awareness Project, or CEAP. The goal of the CEAP is to improve the public's access to and understanding of how major industries are performing under environmental laws and regulations. The pilot phase of this project profiles automobile manufacturing facilities because they are large manufacturers with potential for significant environmental impact. If the pilot phase is successful, the MDEQ hopes to eventually expand this effort into other industry sectors.

Public Participation

MDEQ utilizes many avenues to allow for public participation in addition to the newspaper notification required by the federal program. MDEQ uses (http://www.michigan.gov/deq), the department's "Calendar", online and hard copy publication, (enclosed copy, Appendix E), as well as direct mailing lists and e-mails to notify Canada, affected states, concerned citizens, and local government organizations of permit actions. The public may also be notified about the opportunity to be involved in the process through the letters to all who submitted comments and previously attended public hearings for a specific facility. In some cases, copies of the files are also available at local public libraries.

MDEQ maintains a helpful website. The online information includes the public notice, the fact sheet, the draft permit, and contact information for all NSR permit actions (see enclosed printed copy of the NSR Public Notice Documents, Appendix E).

MDEQ is willing to grant comment period extension requests based on need. For example, if citizens just found out about the project, or if, during the public period not all the information was available for the public, or due to natural causes (such as significantly adverse weather conditions), the public hearing could not be held. (see example for Minergy Detroit, June 12, 2003, Appendix E).

Moreover, MDEQ conducts "enhanced reviews" in which it considers environmental justice issues during a permitting process. This review includes cumulative effects and risk assessments. In the permitting process, MDEQ includes modeling and tests on the background levels and takes into consideration risk factors for elderly and children, as well as hospital statistics and information. For example, in the case of the facilities below, MDEQ looked at blood lead levels when it issued the permits.

FACILITY	YEAR
Genesee Power	1995
Central Wayne	1997
Select Steel	1998
City Medical	1999

Generally, MDEQ finds the secondary standards for NAAQS sufficient for protection of vegetation and soils. However in one case, Cadillac Renewable Energy 373-86C, the analysis included a review of USEPA 450/2-81-078 "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals: Final Report" to establish that ambient concentrations of SO2 had an insignificant impact on vegetation and soil.

Finally, MDEQ also encourages any applicant to involve the public in the permitting process. To facilitate this, MDEQ assigned engineers to set up meetings with the applicant and interested parties. One example is Ford Company and Access (an environmental citizens group), where the company informs the organization about projects and deadlines.

Training

Throughout the years, MDEQ has developed an involved staff training process. MDEQ provides frequent training programs for new and existing employees. New staff are required to complete a specific training regimen.

In addition, MDEQ has developed and held numerous workshops and training sessions for public and industry representatives. One example is the monthly public and industry one-day PTI workshops, which focus on PTI applicability, exemptions, and permit requirements. Another example is the October 2003 one-day PSD workshops (in five locations), developed by MDEQ to help industry and citizens understand the complex federal NSR regulations and how they affect facilities in the state of Michigan. The workshop focused on the Prevention of Significant Deterioration (PSD) program and covered such topics as: PSD

applicability, including the recent reforms to the PSD program; the technical permitting reviews, including top-down Best Available Control Technology reviews and air quality modeling; and the public participation process. Both the flyer and PSD workshop's workbook are included in Appendix D.

MDEQ also issues an informational newsletter "About the Air", with all the updates in air permitting decisions, enforcement, rule changes, or website information updates (the workshop flyer for year 2003 and a copy of the newsletter are enclosed in Appendix D).

Finally, MDEQ provides training and assistance to businesses, institutions and the public to improve the environment and save money by adopting the three "R's:" reduce, reuse and recycle. Known also as pollution prevention, this is a non-regulatory assistance program that provides information, technical assistance and financial incentives to reduce pollution. This effort is done by staff of the Environmental Sciences and Service Division.

File Review

A summary of the file review is included in Attachment A, Files Review. The files included any information submitted from the company, the correspondence between MDEQ and company, public, or USEPA, and public participation documents. In all the reviewed files, the public participation documents included pertinent information regarding the plant and proposed action, the location of available information, a telephone number to request additional information, the date, time, and location of the public hearing (if any), the closing date of the public comment period, and the address where written comments were being received.

The files were organized in a standard structure and easily searchable. They included the emission calculations, along with supporting documentation.

MDEQ stated that any file is available for public review and has a process in place to ensure that the files consistently are well organized, enabling a permanent internal flow of information, and providing the public with necessary or required information in a timely manner.

MDEQ's responses to comments made during the public comment period are thorough and MDEQ uses USEPA guidance and rules to support its responses. The response to comments documents are attached to the final permits in the file review.

Areas of Expertise

Unlike MDEQ's operating permit program, MDEQ's construction permit

program is centralized. All construction permits are issued by the Central Office. The NSR permit applications for sources in the State of Michigan are reviewed by an engineer in one of three units in the Permit to Install Section. The three units are: 1) the Chemical Process Unit, 2) Thermal Process Unit, and 3) the General Manufacturing Unit. Each unit has approximately eight engineers. (See the Organizational Chart in Appendix C). Applications are carefully assigned based on expertise, experience and current workload. The Central Office coordinates its construction permit activities with the Districts to ensure that they are aware of the construction permitting. In addition, the offices perform joint site visits when necessary. This coordination proved to be essential because the Districts are responsible for inspections and for issuing operating permits.

We also believe that there is good coordination not only between MDEQ and the 10 District offices, but also between MDEQ and USEPA, Region 5. In the last year, MDEQ has kept USEPA well informed of individual construction permit issues and most general permit program implementation issues. At the staff level, the permit engineer assigned to draft a PSD permit automatically submits the permit application package to USEPA before or immediately after the 30 day comment period commences. USEPA is provided a copy of the notice and associated documents for all applications requiring public participation. These up-front negotiations have fostered positive working relations between MDEQ and USEPA, and have resulted in quality work products. Since the Audit, MDEQ staff and USEPA have held monthly calls.

B. Areas of Improvement

Approvability of NSR Rules

USEPA approved Michigan's original NSR SIP in 1982. Since 1982, Michigan has made several changes to its NSR rules and has submitted those changes as proposed SIP revisions. On November 9, 1999, USEPA proposed in a Federal Register notice (64 Fed. Reg. 61046) to disapprove the revisions to the Michigan NSR SIP. Some of the issues in this action include public notification requirements, construction before permit issuance, voiding of NSR permits, and relaxation of permit conditions.

The November 1999 proposed disapproval notice included a public comment period which was extended through January 24, 2000. On January 24, 2000, MDEQ submitted comments on the Proposed Rule Disapproving Revisions to Michigan's New Source Review State Implementation Plan, for consideration and inclusion in the public

record. The comments addressed items of general concern, as well as specifically addressing each item of concern.

Since the November 1999 proposed disapproval, MDEQ has continued to work with USEPA in an attempt to resolve the proposed disapproval issues. In July of 2002, MDEQ shared draft rule revisions with USEPA. USEPA provided comments on the draft rules on November 6, 2002. MDEQ completed the state rulemaking process on these rules, and the state rules became effective on July 1, 2003. MDEQ submitted these rules to USEPA for SIP approval. USEPA received the request on October 7, 2003 and is reviewing the submittal.

Michigan has not submitted a proposed SIP revision to address changes made under the Clean Air Act Amendments of 1990.

Synthetic Minor Tracking

Michigan does not currently have a general list of synthetic minor sources that is available for review by the public and USEPA. However, the individual permits cross-reference others, and Michigan has developed an "evaluation form" with additional information. An example of the form, for the Daimler-Chrysler file, is in Appendix C. Additionally, all the districts have different lists and databases, but the existing 1990 computer program is not easy to work with. Aware of the situation, MDEQ is currently working on an updated database, which will be easily searchable, to better track synthetic minor sources. Michigan had hoped to use the new, updated program by fall 2004.

Frequency Evaluation Factor in a Routine Maintenance, Repair and Replacement Exemption

When determining the frequency evaluation factor, MDEQ takes into consideration all of the following: the history of the unit(s) in question, the history of the similar units at the same facility, and the history of similar units at other facilities in the same industry. While the overall emphasis is on the history of the specific unit(s), MDEQ feels that information regarding the history of other similar units at the same facility and the history of similar units at other facilities within the same industry should be taken into consideration. An example of the guidance that MDEQ follows would be the May 23, 2000, letter to Henry Nickel from Francis X. Lyons regarding the Monroe Power plant (the letter is enclosed in Appendix C). However, considering the history of similar units at other facilities within the same industry is not consistent with USEPA policy (recently expressed in utility enforcement actions).

C. Other Noted Aspects of the Program

Permit Issuance Efficiency

Because of general concern from industry that the permitting process is always lengthy, MDEQ is carefully monitoring and trying to minimize the average time taken to issue a PSD permit, starting from the time the application was determined complete (see enclosed Table K1 and K2, Appendix B). MDEQ has had a great deal of difficulty obtaining from sources information necessary to consider an application complete. For example, for auto assembly plants, it takes MDEQ an average of 32 days of engineer time to review a permit application, but has taken an average of 384 days from the date it originally receives an incomplete application for MDEQ to issue a permit. For non-auto sources, review of an application takes about 109 days of engineer time, but final permit issuance takes approximately 363 days.

Nonattainment NSR Program

We did not evaluate the nonattainment NSR program. Prior to the 2003 audit, MDEQ and USEPA agreed that the state did not have to respond to these questions. The audit captured a moment in time – July 21 and 22, 2003. At that time, the entire state of Michigan had been designated attainment for all pollutants since 1999 and there were no non-attainment NSR applications in over five years. Further, there was a large lag time before the designation of non-attainment areas and the release of the ozone and PM2.5 implementation rules outlining the approach Michigan must take. MDEQ and USEPA recognized that, prior to the re-designations taking effect, significant training of staff on the Clean Air Act requirements, Appendix S requirements, new ozone and PM2.5 implementation rules, state rules and any USEPA guidance regarding non-attainment permitting would be needed. This training occurred after the July 21 and 22, 2003 audit.

V. Recommendations

Approvability of NSR rules

MDEQ revised their rules and submitted them to USEPA as stated in section IV.B of this report. The MDEQ also recognizes that most of the approval issues and arguments are very technical and will likely require additional discussion. MDEQ expressed the intention to work with USEPA to find solutions and obtain approval of its NSR SIP. We appreciate Michigan's commitment to have a SIP-approved NSR program. We recommend that USEPA and MDEQ continue discussions towards this end.

Synthetic Minor Tracking

We are encouraged by MDEQ's efforts to track synthetic minor limitations. The importance of this effort is magnified by the NSR reform changes USEPA has made in the federal program. We recommend that MDEQ remain focused on the development of its tracking system. Frequency Evaluation Factor in a Routine Maintenance, Repair and Replacement Exemption

In making RMRR determinations, Michigan should discontinue consideration of the frequency with which other sources in an industry perform similar maintenance, repair or replacement projects.

VI. MDEQ Concerns with the Required Program

Public Notice Requirements

Although over 40% of the PSD permits where comments are received are revised due to the comments, no comments from the public have been received for synthetic minors. MDEQ continues to express concern regarding the public noticing of synthetic minor permit applications less than the 90% major threshold level. Michigan's original SIP, approved by USEPA in 1973, provides for a 21-day public comment period for a number of sources, including PSD applications and those that the agency judges to potentially have significant air quality impact, or that are the object of substantial public concern. As the program matured, additional public comment requirements were added, including public comment for all major sources and modifications as defined by the CAA, as well as any permit application for which there is a known public controversy. These new requirements make the public participation requirements more stringent than the plan already found to meet the requirements of 40 C.F.R. § 51.161.

USEPA's position is the added public review provided for by Rule 205(3) does not adequately address its concerns regarding public comment for synthetic minor sources or that the 90 percent emission threshold has not been adequately demonstrated. The 90 percent threshold was selected after review of a number of years of permitting and public commenting on synthetic minor sources. Michigan found that it did not receive comments on synthetic minor sources whose emission limit caps were less than 90 percent of the major source threshold when they were public noticed. In 1996, 52 synthetic minor permits were issued with 31 having public notice. No comments were received for any permit with synthetic minor limits below the 90 percent threshold. require such an administrative burden as well as a direct cost to the agency of newspaper notices, hearing locations and other expenses of \$1,300 - \$1,500 for each permit that goes out for public comment, as well as the time and cost to the applicant due to the delays, must be considered. The MDEQ has instead focused on those applications and sources where there is public concern and provided enhanced public

participation such as Informational Meetings, direct mailings, etc.

Training

The December 31, 2002 NSR Reform regulations became effective in attainment areas in the state of Michigan on March 3, 2003. Like many of the states, MDEQ staff felt that additional NSR Reform training would be helpful.

Inconsistency of Program Application Nationwide

Finally, one general concern that MDEQ has is related to the inconsistency of program application, not only within Region V, but also nationwide. By comparing the reviews done by other states, MDEQ feels that other states are not held to the same standard they are. Many are not required to use the top-down BACT process. Although recognizing there can be slight differences in determinations, MDEQ found that the level of technology required and/or the level of documentation necessary to demonstrate that a technology is infeasible or too costly is far higher in Region V versus the other areas of the country. As a result, MDEQ feels that they are being held to a much higher standard to the detriment of the state's economy. Currently MDEQ is re-evaluating the rules/requirements and our interpretation and implementation of them to determine what they believe are the appropriate levels of review and documentation.

VII. Audit Questionnaire

Note: This questionnaire does not address implementation of changes made to the major NSR rules in EPA's rulemaking on December 31, 2002.

Unless otherwise stated, this review will cover permits issued in the last five years.

1. Netting

NO 1. Is netting approved in your NSR SIP for determining whether modifications at major stationary sources are subject to major NSR (PSD or nonattainment NSR as applicable)? If no, please explain.

I) Program Requirements Common to Both Prevention of Significant Deterioration (PSD) and Nonattainment NSR

Answer: MDEQ does not have an approved NSR SIP and is delegated to implement the federal program for 40 CFR 52.21 (September 26, 1988 delegation letter is enclosed in Appendix C). The question is N/A for NAA, because for the last 5 years all areas in Michigan have been attainment areas.

YES 2. Is your contemporaneous look-back period five years, exactly the same as in the Federal PSD regulations at 40 CFR 52.21. If not, what is the contemporaneous time period for netting in your SIP?

Note: MI is delegated to implement federal rule 52.21, therefore the contemporaneous look-back period is five years. A permit example is enclosed in Appendix D (Draft Permit B3692 for Packaging Corporation of America).

YES 3. For determining the baseline from which emission reductions are calculated do you require the applicant to submit the actual emissions from the units along with any permit limits that apply?

Note: An example of this practice is enclosed in Appendix D (Holcim Draft Permit 60-710).

NO 4. Do you allow an applicant to receive emission reduction netting credit for reducing allowable emissions instead of actual emissions? If yes, please explain.

Note: MDEQ does not allow an applicant to receive emission reduction netting credit for reducing allowable emissions. Only the actual emissions are considered in the calculation. An example is enclosed in Appendix D (Holcim Draft Permit 60-710).

NO 5. Do you allow an applicant to receive emission reduction credit for reducing any portion of actual emissions that resulted because the source was operating out of compliance?

Note: MDEQ follows the draft NSR Workshop manual, and documents page A.41. The pertinent paragraph states that "a source cannot receive emission reduction credit for reducing any portion of actual emissions which resulted because the source was out of compliance".

- NO 6. Do you allow an applicant to receive emission reduction credit for an emissions unit that has not been constructed or operated?
- YES 7. Are emissions reductions to meet MACT requirements

eligible for netting credits? If yes, under what conditions? (See EPA's November 12, 1997 memo from John Seitz entitled "Crediting of Maximum Achievable Control Technology (MACT) Emission Reductions for New Source Review (NSR) Netting an Offsets".)

Answer: MDEQ states that they follow the memo as written (memo is enclosed in Appendix C).

- YES 8. When any emissions decreases are claimed as part of a proposed modification, do you require that all stationary, source-wide, creditable and contemporaneous emissions increases and decreases of the pollutant be included in the major NSR applicability determination?
 - 9. To avoid "double counting" of emissions reductions what process do you use to determine if emissions reductions considered for netting have already been relied on in issuing a major NSR permit for the source?

Answer: With regards to avoiding "double counting" of emission reductions, at the time the netting is reviewed, MDEQ ensures that the actual decreases occurred at the same stationary source and are federally enforceable - they make sure the equipment has been removed and the permit is voided, or the permit is revised to accommodate the change in emissions or process needed for the netting. This is documented in the engineer's evaluation, the permit conditions for the approved project, and the public participation documents. All permits involving a netting exercise are public noticed. During the review process, prior to the use of any credits MDEQ verifies the status of the equipment through our permitting system and the emission inventory. Active and voided files are reviewed and the calculations are verified to ensure that the emission reductions are credible and clearly have not been previously relied upon.

NO 10. Do you have a process to track projects that use credits to net out of major NSR? If yes, please explain.

Note: All credits are documented in the permits. MDEQ can track the credits for each individual source by keeping data about a source in one place and assigning one person to a company, but there is no state-wide database yet; nevertheless, MDEQ is working on a program to track projects that used netting out of PSD.

YES 11. Do you require that emissions reductions (e.g., reductions from unit shutdowns) must be enforceable to be creditable for netting?

Note: An example of this practice is enclosed in Appendix D (Permit No. 153-73D for Woodbridge Corporation).

- NO 12. Have you had public concerns regarding the netting analysis and procedures used for any issued permits that avoided major NSR? If yes, please describe.
- NO 13. Do you allow interpollutant trading when netting, e.g., can a source use NOx or PM credits for netting out of VOC increases? If yes, please explain.

Note: MDEQ does not have any requests since for the last 20+ years. MDEQ follows the EPA guidance (Page A.39 of the draft New Source Review Workshop Manual, which states "[r]eductions must be of the same pollutant as the emissions increase from the proposed modification and must be qualitatively equivalent in their effects on public health and welfare to the effects attributable to the proposed increase.")

14. What process do you have to verify that a source's emissions reductions considered for netting, including emissions reductions that may have been "banked," are not already used by the source, or another source, as nonattainment NSR offsets? Please describe.

Answer: MDEQ verifies that a source's emissions reductions considered for netting are not used as offsets by tracking those emissions for each source: MDEQ requires all sources to document the emissions reductions, and the emissions information about a source is in the source's permit files.

- 2. Routine Maintenance, Repair, and Replacement (RMRR)
- YES 1. Do you have knowledge of the EPA letter dated May 23, 2000, to Henry Nickel of Hunton & Williams concerning Detroit Edison and the Wisconsin Electric Power Company (WEPCO) case RMRR documents?

A copy of the letter is enclosed in Appendix C.

2. What other documents do you rely upon when making RMRR exemption determinations?

Answer: As a delegated state to implement the PSD program, MDEQ uses applicable state rules 285 (a), (b), and (c) (enclosed in Appendix B). These rules define the permit exemptions.

NO 3. Do you have a formal protocol for making RMRR exemption determinations? If yes, describe the protocol.

Answer: MDEQ is using the DTE Conners Creek Determination. If the rule doesn't clearly apply to a permit, MDEQ asks the company to apply for a permit.

4. Approximately how many formal RMRR exemption determinations have you made in the last five years? Using any one such determination as an example, describe the example, state the conclusion you reached, and discuss how you reached the conclusion.

Answer: MDEQ made 2 formal RMRR exemptions. An example would be the Conners Creek Power Plant. This involved the conversion of four existing boilers originally designed and used to burn coal to burn natural gas. Detroit Edison contended that the plant had been on extended cold standby. AQD, USEPA and WCAQMD investigated the scope and extent of the maintenance and repairs that were being made at the Plant. The findings were compared to existing USEPA related policy guidance and memoranda. On July 16, 1998, the agencies determined that the actions triggered NSR permitting requirements, NSPS, and PSD. Detroit Edison filed a complaint in Federal District Court. The Judge found that Detroit Edison had violated the CAA when it renovated, restarted, and operated the plant without first obtaining the necessary permit. The company submitted the application, and, ultimately received a PSD permit. In addition, many additional informal reviews are made both by permit and field staff as they routinely respond to questions raised in meetings, telephone calls, and inspections. There is no requirement for the agency to provide formal reviews. Ultimately, MDEQ feels that it is the applicant's responsibility to ensure they are complying with all aspects of the rules. Otherwise the facility may be subject to enforcement action.

YES 5. Do you keep documentation of formal RMRR exemption determinations?

Note: MDEQ keeps track of the formal RMRR determinations (there are 2).

YES 6. Do you restrict the RMRR exemption to units being modified and exclude replacement of entire units from RMRR exemption consideration?

Note: There is no "entire" units replacement under RMRR exemption.

YES 7. Regarding the "purpose" evaluation factor in an RMRR exemption evaluation, do you exclude projects from the RMRR exemption that result in an increase in production capacity?

8. Regarding the "frequency" evaluation factor in an RMRR exemption evaluation, do you consider just the history of the specific unit(s) in question, just the history of other similar units at the same facility, just the history of similar units at other facilities in the same industry, or some combination of these histories?

Answer: MDEQ considers this a case-specific determination. They rely upon EPA's guidance to determine what frequency evaluation factor to consider. An example of the guidance that MDEQ follows would be the May 23, 2000, letter to Henry Nickel from Francis X. Lyons regarding the Monroe Power plant (the letter is enclosed in Appendix C). While MDEQ's overall emphasis is on the history of the specific unit(s), information regarding the history of other similar units at the same facility and the history of similar units at other facilities within the same industry may sometimes be taken into consideration. For example, on pages 2 and 3 of the May 23, 2000 document, the focus is on the discussion of the historical blade replacements performed at Detroit Edison, but also states "[T]he project goes well beyond routine turbine maintenance, repair and replacement activities for the utility industry in general".

9. Regarding the "cost" evaluation factor in an RMRR exemption evaluation, what procedure do you follow to take cost into account?

Answer: MDEQ doesn't have a formal procedure, because there is no EPA guidance or formal rules in this regard; MDEQ is using the comparison between the routine vs. replacement costs.

YES 10. Do you provide RMRR exemption evaluation training to NSR permitting staff employees (other than on-the-job training)? If yes, describe the nature of the training provided.

Answer: MDEQ staff is exposed to OECA, EAB, states, and court determinations and trained on RMRR exemptions. This training includes formal Field and/or Permit Section meetings where group discussions are held on specific topics such as routine maintenance, individual discussions and review of guidance documents when issues are raised, emails and articles written regarding a specific issue review of recent determinations, as well as on-the-job training sessions.

YES 11. Do you provide an information outreach program on RMRR exemption evaluations for owners of regulated sources? If yes, how frequently do you provide such information and how do you provide it?

Answer: The outreach activity includes: monthly 1-day PTI workshops to community (examples of the flyers are in Appendix E); there is a newsletter (electronically or hard copy) ("About the Air"), with the recent permitting and enforcement decisions (examples of the emails/hard copy are in Appendix E); there is also a small business assistance program that train owners about the permitting process, exemptions. MDEQ's Environmental Assistance Division also edits a fact sheet "Air Pollution Control 101" with info about MDEQ/AQD, air pollutants, state and federal rules and regulations (the fact sheet is enclosed in Appendix E).

3. Synthetic Minor Limits

NO 1. Do you keep a list of synthetic minor sources (i.e., sources that would otherwise be major for NSR but are considered minor because of emissions limits or other limiting conditions in their permits) that is available for review by the public and EPA? If yes, please explain this tracking system and how it is updated.

Note: Due to the high volume, MDEQ does not keep a general list of synthetic minor sources. However, the districts have their own lists/database. For every permit an "evaluation form" (including the emission information) is developed and the individual permits cross-reference previous permits. An example of the evaluation form in enclosed in Appendix D, for the Daimler-Chrysler file, also reviewed during the audit (Audit Part 2, File Review). In this case the company has elected to take permit conditions to make it a synthetic minor source under PSD and to opt-out of Title V. Currently MDEQ is working on developing a centralized database to better track synthetic minor sources.

YES 2. Do you include "prompt deviation" reporting requirements in synthetic minor source permits? If yes, how do you define "prompt deviation"?

Answer: Pursuant to Rule 912 (Appendix B), MDEQ considers "prompt deviation" reporting requirements a part of the general conditions of every permit. This rule deals with notifications and reporting requirements of violations of emission limits; "prompt deviation" means "as soon as reasonably possible, but not later than 2 business days". An example is enclosed in Appendix D (Permit No. 283-01 for The Kellogg Company).

YES 3. Do permit applications your agency reviews, and permits issued identify the requirements (e.g., PSD, nonattainment NSR, Title V, NESHAP) being avoided by keeping the source

minor?

Answer: Pursuant Rule 205 (Appendix B), MDEQ identifies and includes the requirements that are avoided by keeping a source minor in the staff report, evaluation form, and file. An example is enclosed in Appendix D (Draft Permit No. 355-97A for Valley Asphalt Company, Inc).

4. Describe your formal process for establishing or designating a synthetic minor source.

Answer: Any source must send a permit application/request for a synthetic minor permit. The application includes all the emissions information. MDEQ checks the emission inventory and draft emission limits according to the federal and state guidance. Establishing or designating a synthetic minor source is described in Rule 205 (Appendix B), and the enclosed intra office April 1998 Seitz Memo for staff (drafting limits included, Appendix C); MDEQ has a formal procedure for writing synthetic minor permits (enclosed internal guidance, effective 10/04/2001, Appendix C). This procedure consists of 7 steps:

- 1) Identify the regulation from which the source whishes to avoid applicability.
- 2) Write the permit conditions to have applicability that is identical to the regulation that is being avoided.
- 3) Include a method of determining compliance for the synthetic minor limit.
- 4) Ensure that the limit is practically enforceable.
- 5) Provide for public comment
- 6) Note the underlying applicable requirements in the permit
- 7) Note the reason for the synthetic minor limit in the permit's Evaluation Form.
- YES 5. For synthetic minor sources do your permits include enforceable limits to keep the sources minor?

Note: State Rules (205, 911, and 912, enclosed in Appendix B) require that synthetic minor permits include all the operational emission limits. An example is the enclosed Final Permit No. 143-02 for Delphi Saginaw Steering Systems, and General Permit (Appendix D).

6. How is compliance with the synthetic minor limits tracked over time? Please explain.

Answer: Each synthetic minor permit requires recordkeeping and reporting for various key parameters, in order to assure on-going compliance. In order to document this compliance, MDEQ requires deviations reports to be submitted. The district field inspectors check the compliance with the conditions of the permits according

their inspection schedules.

YES 7. Are you satisfied that your tracking activities are sufficient to ensure that sources getting synthetic minor permits to avoid major NSR review are not actually operating above the applicable major source threshold?

Note: MDEQ is currently working on developing a centralized database to better track synthetic minor permits.

YES 8. Do you include in your synthetic minor permits conditions requiring sources to notify you if and when the major source threshold is reached?

Note: Conform state Rule 912 (Appendix B), a source must report any deviation, and, in this case, reaching the threshold is considered a deviation from permit conditions.

- YES 9. Do you perform (or require) modeling for sources seeking synthetic minor permits to determine impacts on PSD increments?
- YES 10. Do you consider visibility issues in Class I areas, if applicable, when reviewing synthetic minor applications?

Note: The only Class I area in MI is in the Upper Peninsula.

- 4. Pollution Control Projects (PCP) Exclusion
- YES 1. Do you have standard permitting procedures or rules that allow for certain changes at non-utility emissions units to be designated as PCP, which are excluded from major NSR?

Answer: MDEQ requires the applicant to send a permit application and to apply for PCP permit as for any permit (including public participation requirements, modeling analysis, etc.). Now MDEQ follows the December 31, 2002 NSR Reform requirements. Before March 2003, MDEQ had followed 1994 Seitz Memo (enclosed, Appendix C).

2. How many PCP exclusions have been granted for "feed" or "fuel" switches?

Answer: Since 1994 (Seitz Memo, enclosed, Appendix C) MDEQ granted many PCPs. There are no numerical records on the type of PCPs on file, because the permits are not organized by type, but by the source name.

3. What process do you use to determine if the project is "environmentally beneficial" and not just "economically

efficient"?

Answer: Based on the info received through the permit application, MDEQ only determines the environmental benefits (the emissions impact). The "economical efficiency" is not a weighted factor.

4. How are the collateral emission increases evaluated? Do you require a modeling analysis to demonstrate insignificant impacts from emissions increases?

Answer: All PCP's are required to meet the "cause or contribute" test to demonstrate that the project does not adversely impact an Air Quality Related Value (AQRV). A modeling analysis is required, and the collateral emission increases are evaluated, through modeling, on a case-by-case basis.

5. How do you handle collateral increases in hazardous air pollutants (HAP)?

Answer: MDEQ follows the Air Toxic Rules 224 and 225 (Appendix B), which describe the T-BACT and health-based screening level requirements for new and modified source of air toxics. However, it can also be a case by case situation (for example, if 112(g) applies, then PCP exclusion would not be possible).

NO 6. Are the emission reduction credits from PCP available for netting or NSR offsets? Please explain.

Answer: This issue has not come up. Currently, there is no rule or guideline that would allow a source to use emission reduction credits from PCP for netting or NSR offsets.

7. Which add-on control devices are most frequently involved in PCP exclusion requests?

Answer: Low Nox Burners are the most frequently used.

8. Which types of industrial sources typically request PCP exclusions from major NSR?

Answer: Usually facilities with large boilers (such as utilities or wood products industry) request PCP exclusion from major NSR.

NO 9. Does your NSR SIP include the PCP exclusion for electric utility steam generating units (often referred to as the WEPCO exclusion)?

Note: The PCP exclusion is implemented through the PSD program

delegation (MDEQ does not have a SIP approved).

5. Fugitive Emissions

1. Please provide your regulatory definition of "fugitive" emissions for major NSR applicability purposes and how does it differ from the federal definition.

Answer: The definition that MDEQ is using, Rule 106 (1), does not differ from the Part 51 federal definition. Rule 106 (1) defines "fugitive emissions" as those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

YES 2. Do you make a distinction between "fugitive" emissions and "uncontrolled" emissions? If so, please explain.

Answer: The uncontrolled emissions are defined in Rule 121 (a) (enclosed in Appendix B). They are defined as those emissions expected to occur without control equipment, unless such control equipment is, aside from air pollution control requirements, vital to production of the normal product of the process or to its normal operation.

YES/ NO 3.Do you include fugitive emissions in major NSR applicability determinations for new sources? For modified sources? Please explain.

Answer: MDEQ includes fugitive emissions in major NSR applicability determinations for the 28 categories sources and HAPs, but not for the modified sources, because there the NSR Reform applies (baseline is projected actuals).

YES 4. Do you allow major sources to use reductions in fugitive emissions for netting purposes? If so, please explain, and describe how you determine the fugitive emissions "baseline" used for netting.

Answer: MDEQ would only allow major sources to use reduction in fugitive emissions for netting purposes if the reductions are quantifiable, are enforceable as a practical matter, and were considered as part of the baseline. The 28 PSD sources consider fugitive emissions. The baseline is determined on a case by case basis. Factors that must be considered is the methodology used to determine the fugitive emissions such as emission factors (pounds per 1000 pounds processed) or testing, and the corresponding operational parameter (pounds processed) for the baseline time period. It is

important to note that the answer provided did not include the NSR reforms which provided additional guidance. As a delegated state, Michigan is obligated to implement the 12/31/2003 reforms.

5. Please provide a description of your guidelines or calculation methodology used to quantify fugitive emissions.

Answer: MDEQ looks at the emission factors (AP-42), any road activities, and generally at any source specific guidance for emissions inventory. This is especially helpful for sources with many emission factors.

YES 6. Do your permits contain conditions for specific emission limits or control methods/work practice standards for fugitive emissions consistent with requirements for BACT?

Note: The conditions include mass balance, fugitive dust plans (especially in the chemical industry), and work practices.

6. Modeling

YES 1. Do you follow EPA's modeling guidelines in 40 CFR Part 51 Appendix W?

Answer: MDEQ air modeling staff feels that it is very important to do so.

NO 2. Are deviations from the modeling guidelines in Appendix W subjected to public comment and submitted to the regional EPA office for approval?

Note: There are not many deviations; also, any single facility can't use more than 80% of available increments for criteria pollutants.

YES 3. Are minor permit actions (i.e., proposed new and modified minor sources), evaluated to determine if modeling for PSD increments is needed? Under what circumstances is increment modeling triggered for these minor permit actions?

Answer: If the new emissions are below the significant level, then no modeling is required (except if the source is in a sensitive area, such as Class I area).

YES 4. Do you ask applicants to submit a modeling protocol for approval prior to submitting modeling?

Note: The modeling protocol is recommended for all major NSRs (PSDs) and the controversial ones.

YES 5. Is the protocol provided to other interested organizations (e.g., EPA, Federal Land Manager)?

Note: It is not a standard procedure; the modeling protocol is provided only if requested.

YES 6. Is the effect of downwash modeled if stacks are less than good engineering practice (GEP)?

Note: MDEQ is using a standard program (called "BPIP") to determine the downwash. BPIP (Building Profile Input Program) is an EPA designated utility to assist unique modeling problems associated with building wake effects.

- YES 7. Are modeling analyses available for public review?
- YES 8. Do you review modeling submittals to determine if option switches are correct?

Note: MDEQ air modeling staff always remodel the data received.

9. When off-site meteorological data are used what years are typically used?

Answer: MDEQ uses data from the National Weather Services because there are no independent meteorological stations. Usually for on-site data last year is considered, and for off-site data the most recent 5 years that MDEQ can validate (as of today they are 1987-1991).

10. How do you train your modeling staff?

Answer: Although there is a formal training for senior staff, usually the training is informal (peer training, on-site training, calls participation, and assignments to gradually complex applications)

- YES 11. Do you follow The Air Quality Analysis, Additional Impacts Analysis, and Class I Area Impact Analysis guidance provided in the New Source Review Workshop Manual (Draft October 1990)?
 - 12. For cumulative national ambient air quality standards (NAAQS) and PSD increment compliance assessment:
 - a. How are the appropriate emission inventories of other sources developed?

Answer: MDEQ has 2 databases used to determine offsite emissions inventory: the permit files, including the PTE emissions data, and the MARs database, with the actual emissions (the grand-fathered sources are using the actuals). Both databases' data are compared in order to determine the emissions inventory.

b. What are the reasons used to identify and/or eliminate emission sources?

Answer: If the emission source is in the emission inventory file, it will be included, unless it's voided or removed for any reason except Title 5. If a source is voided, it has to go through the permitting process. Also, a source that shuts down for a number of years cannot use the credits for offsets.

c. How are PSD increment consuming/expanding sources identified and tracked?

Answer: MDEQ is using the permits' dates. The increments are identified by the consecutive numbers of years that permits are issued after baseline date, and tracked in permit files (each permit has a number). One area of difficulty is tracking the increments from grandfathered facilities.

NO d. Are mobile sources modeled for increment compliance?

Note: The mobile sources are not modeled because there is no actual emission changes in mobile sources compared with baseline emissions. Nevertheless, the mobile sources are considered for the incremental compliance.

13. What is the basis (e.g., allowable, maximum or average actual short-term emissions, last two year period, etc.) of the emission rates provided in the NAAQS and PSD increment consuming inventories of other sources?

Answer: It is done by date, pre and post baseline approach.

14. How do you ensure that the controlling concentrations reported by the applicant for each pollutant and averaging period were appropriately determined?

Answer: First of all, MDEQ makes sure that the correct data is used in the permit applications. The reported emission rates and modeled emission rates are compared to the model run and the permit. Secondly, there is a constant dialog between permit engineers, modelers, and

applicants. Permit engineers (and permit writers) are using their technical expertise and data on hand to provide the numbers to the air modelers.

YES 15. Are the impact modeling analyses reviewed to ensure that they are accurate and complete, and that appropriate modeling procedures (e.g., modeled to 100-m resolution, fence line and not property line, nearest modeled receptors, etc.) were followed?

Note: Usually MDEQ staff remodels the air modeling received (sometimes more than once). In order to find the maximum impact ("hot spot", as the modelers call it), MDEQ uses a maximum of 25 m air boundary (fence line), a maximum of 50 m resolution, and data collected every 100 m after several kilometers.

YES/ NO 16. Is complex terrain an issue in your region? What modeling procedures are used to address impacts in complex terrain?

Answer: The geographical complexity of the area triggers the complexity of the modeling procedures. For example, if the flat areas and rolling area terrain deviations in the receptor area are more than 25% of the shortest stack, the terrain is included in the modeling. A modeling procedure used to determine the terrain heights is AERMAP, with the possibility to use in the future another modeling procedure, AERMOD. The AERMOD is actually a modeling system with three separate components: AERMOD (AERMIC Dispersion Model), AERMAP (AERMOD Terrain Preprocessor), and AERMET (AERMOD Meteorological Preprocessor). Special features of AERMOD include its ability to treat the vertical inhomogeneity of the planetary boundary layer special treatment of surface releases, irregularly-shaped area sources, a three plume model for the convective boundary layer, limitation of vertical mixing in the stable boundary layer, and fixing the reflecting surface at the stack base. A treatment of dispersion in the presence of intermediate and complex terrain is used that improves on that currently in use in ISCST and other models, yet without the complexity of the Complex Terrain Dispersion Model-Plus (CTDMPLUS). extent practicable, the structure of the input or the control file for AERMOD is the same as that for the ISCST3. At this time, the AERMOD contains the same algorithms for building downwash as those found in the ISCST3 model.

The AERMET is the meteorological preprocessor for the AERMOD. Input data can come from hourly cloud cover observations, surface meteorological observations and twice-a-day upper air soundings. Output includes surface meteorological observations and parameters and vertical profiles of several atmospheric parameters.

The AERMAP is a terrain preprocessor designed to simplify and standardize the input of terrain data for the AERMOD. Input data include receptor terrain elevation data. The terrain data may be in the form of digital terrain data that is available from the U.S. Geological Survey. Output includes, for each receptor, location and height scale, which are elevations used for the computation of air flow around hills.

YES 17. Are pollutants without NAAQS and/or PSD increments addressed in the air quality impact assessments? What threshold concentrations (e.g., acceptable ambient concentrations) are used to evaluate impacts?

Answer: MDEQ includes in any air quality impact assessment the long and short term effects on the maximum impact boundary, as well as the carcinogenic and non-carcinogenic limits (Initial Threshold Screening Level, or ITSL and Initial Risk Screening Level, or IRSL). The list of these screening levels is developed by the Air Quality Division and updated via the webpage on a weekly basis. The threshold concentrations depend on the pollutant. All these information are available for public in the MDEQ's webpage.

YES 18. Do you have written agency-specific air quality modeling guidance for use by applicants? If yes, has the guidance been provided to other concerned organizations (e.g., regional EPA, appropriate FLM, etc.) for review and comment? Is your quidance available on the internet?

Answer: MDEQ is using the Michigan Air Use Permit Technical Manual and Air Quality Dispersion Modeling. These are available for public in the MDEQ's webpage. A copy of the manual is enclosed in Appendix C.

19. How do you determine the appropriateness of proposed meteorological data for an application? When are "on-site" meteorological data required for an application? Are "on-site" meteorological data validated and accepted if recovery is less than 90 percent?

Answer: In order to determine the appropriateness of proposed meteorological data for an application, MDEQ follows the EPA guidelines and pre-processes the data. The "on-site" meteorological data is requested when is part of the PSD permitting requirements.

20. When an applicant's air quality modeling reveals NAAQS and/or PSD increment violations, what is required to grant the permit and how are the violations resolved?

Answer: Per Rule 207 (Appendix B), MDEQ grants a permit to an applicant with permit violations only if the applicant emissions don't have a significant contribution to the significant PSD level.

YES 21. Do your regulations include the federal definition of ambient air? If no, what is your definition of ambient air?

Note: The interpretation from the policy memorandum definition is the same as in 40 CFR Part 51 Appendix W.

22. Discuss your procedures for modeling "hot spots," including minimum receptor spacing?

Answer: MDEQ uses a maximum of 25 m along fenceline in order to maximize the "hot spots". The maximum impact is then determined through calculations and measurements.

23. How do you determine if background air quality data are representative?

Answer: MDEQ uses sites close to the source and looks at the sources in the monitor area, then compare that to the area where the applicant is located. For accuracy, MDEQ uses own monitor data and EPA's Air database.

YES 24. Do you use the same NAD for stack, receptor, and building UTM coordinates?

Note: MDEQ also finds useful to use USGS map, TerraFly and MapQuest.

7. Stationary Source Determinations

YES/NO1. Do your SIP-approved rules define stationary source differently than 40 CFR 51.165 or 51.166? If yes, please explain.

Answer: Michigan is a delegated, not a SIP approved state (since September 26, 1988). Currently, the Rule 119 (r) is using a combination of Part 51 and Part 71 definitions for stationary sources: all buildings, structures, facilities, or installations which emit or have the potential to emit 1 or more air contaminants, which are located at 1 or more contiguous or adjacent properties, which are under the control of the same person, and which have the same 2-digit major group code associated with their primary activity. In addition, a stationary source includes any other buildings, structures, facilities, or installations which emit or have the potential to emit 1 or more air contaminants, which are located at 1 or more contiguous or adjacent properties, which are under the control of the same person,

and which have a different 2-digit major group code, but which support the primary activity.

Part 51 defines stationary source as any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

Part 71 defines stationary source as any building, structure, facility, or installation which emits or may emit any air pollutant or any pollutant listed under section 112(b) of the Act.

YES 2. When determining if emissions units are contiguous or adjacent, do you assess whether emissions units under common ownership or control may be a single stationary source regardless of the distance between the emissions units? Please explain.

Answer: MDEQ follows the June 21, 1996 Operational Memorandum regarding Stationary Source Determinations (enclosed in Appendix C). This memorandum elaborates on the definition of the term "stationary source" and provides background information and guidance on the steps involved in making a determination of which components of a facility are required to be included in specific stationary source determinations. The procedural steps in making the determination are:

- 1). Evaluate the spatial relationships if multiple properties are involved, i.e., are they "adjacent or contiguous"
- 2). Evaluate the "control" relationship, i.e., if the entities are "under the control of the same person"
- 3). Determine the industrial grouping relationship. If any of the listed criteria do not apply, the entities are treated as separate stationary sources.
- YES 3. Do you assess facilities' financial, personnel, and contractual relationships to determine common ownership or control?
- YES 4. Do you assess whether sources with different first two-digit SIC codes (i.e., emissions units not in the same industrial grouping) may qualify as separate stationary sources?

8. Debottlenecking and Increased Utilization

YES 1. When determining if proposed modifications are subject to major NSR, do you include emissions increases from existing emissions units that are not physically modified (i.e., units that will be debottlenecked or have increased utilization such as boilers)?

Note: An example of this procedure is in the Fact Sheet for Hillman Power Company's permit No. 687-86G (enclosed in Appendix D).

2. What method is used to determine the emissions increase from these emissions units? What EPA guidance do you consider for this issue?

Answer: MDEQ follows several guidance Memos (the latest is the September 18, 1989 EPA guidance Memo "Request for Clarification of Policy Regarding the Net Emissions Increase", enclosed in Appendix C). As a standard operational procedure, MDEQ considers the entire process, and all the ramifications of a bottleneck situation.

YES 3. Do you train your permitting staff to include such emissions increases when determining if a modification is major for NSR?

Note: The training is mostly on the job training, including series of training sessions and section meetings every 6 weeks.

- 9. Relaxation of Limits Taken To Avoid Major NSR
- 1. What types of changes do you consider potentially subject to relaxation assessments?

Answer: Pursuant to Rule 205 (enclosed in Appendix B), any change in limits established to make the source a synthetic minor would require reassessment.

YES 2. Do you have a written policy on relaxation assessments?

Answer: Michigan follows the rules: 201(1), which states that a change in a permit condition is a modification which requires a permit to change an existing limit, and 205(1)(a), which states that any synthetic minor permit from NSR must meet two criteria: practical enforceable emission limitation and a process restriction (i.e. a production or an operational restriction). A relaxation in a permit limitation is further addressed as the requirement to apply rules R336.1201 and R336.1220, which list the Permits to Install requirements in attainment and nonattainment areas. These rules are applied to the source or modification as though construction had not yet commenced. In addition, Michigan follows federal guidance on sham

and staged construction permitting as well.

3. Approximately how many relaxation assessments have you made in the last five years?

Answer: It is difficult to answer to this question, because MDEQ has no centralized tracking system in place for all the relaxation assessments, but is currently working in developing one.

YES 4. Do you include specific permit limits and conditions to make potential future relaxation possibilities more identifiable?

Note: The limits are clearly defined in each permit and the permit writer can easily verify past modifications on a permit and identify potential relaxations.

5. What is your understanding of the appropriate circumstances under which an existing minor source is allowed a 100/250-tons-per-year emissions increase without triggering relaxation provisions?

Answer: If the existing source is a synthetic minor source the issue or possibility of sham and/or staged construction must always be considered. Other than above, if the existing emission units are not modified or debottlenecked then there is no issue. If they are modified or debottlenecked and are not an issue for sham or staged construction, then they are subject to NSR review with the new major source modification.

YES 6. Do you provide relaxation evaluation training to NSR permitting staff employees (other than on-the-job training)? If yes, describe the nature of the training provided.

Answer: Besides the on-the-job training, there are meetings for training purposes, and various cross-training sessions. In addition, all permit writers must attend a formal NSR training.

10. Circumvention/Aggregation Issues

- YES 1. When you review a modification to determine if it is major for NSR, do you consider aggregating prior minor emissions increases at the stationary source?
 - 2. Please provide any criteria you may use to determine if a series of minor modifications or projects needs to be aggregated for NSR applicability purposes?

Answer: MDEQ is reviewing these situations on a case by case basis, analyzing available information (technical, legal, and financial) that may determine the correlation between small changes. To avoid lack of communication and waste of knowledge, MDEQ assigns, on a project-by-project basis, the same engineer(s) to a company.

- YES 3. When requests are made to permit new or modified emissions units as separate minor changes over time, do you evaluate whether the permitting process is purposely staged as minor when the changes are really one permitting action subject to major NSR?
 - 4. How do you track multiple modifications at a source over a short period of time?

Answer: Usually the company must send 2 copies of the permit application, one to the Lansing Office and one to the district (for the inspectors, who might or might not perform inspections to the source). The information is available to all districts' staff: there is a file docket where each file is labeled and numbered and removal of any of them involves signatures. This system also allows easy search on how many applications have been submitted regularly.

After the application is received, the field inspectors inform the permit engineers about specific issues at the source. Only if everything complies will all federal and state rules, MDEQ would issue the permit (which sometimes has to go through the public comment period).

II) Prevention of Significant Deterioration (PSD) *

* Note: The PSD program implements part C of Title I of the Clean Air Act for new or modified major stationary sources.

1. Program Benefits Quantification

YES 1. In your opinion, is the PSD program an incentive to reduce emissions below major source levels?

Note: MDEQ feels that the PSD program is an incentive to "synthetic minor" a permit, mainly because of the sources' perception that applying for a PSD is always a complex and lengthy process.

NO 2. In your opinion, have PSD permits been used as the authority to implement other priorities such as toxic emission reductions and improved monitoring and reporting?

Note: MDEQ already has a delegated toxic program, which includes T-BACT analysis (Rule 224 - enclosed in Appendix B - lists the requirements for new and modified source of air toxics).

- YES 3. In your opinion, does the case-by-case nature of a PSD permit allow you to implement emission reducing programs or controls more quickly than rulemaking?
- NO 4. In your opinion, does the PSD program provide communities a mechanism to be involved in improving their own air quality?

Note: MDEQ staff feels that, although there is some help from the citizens, mainly through the appeals, usually they oppose the proposal, and not based on PSD rules. Improving this situation is the on-going citizens training that the state and EPA are providing in different locations throughout the state.

YES 5. In your opinion, has the PSD program contributed to sustaining good air quality?

2. Best Available Control Technology (BACT)

YES 1. Do you require permit applicants to use the "top-down" method for determining BACT? If no, what approach do you require?

Note: As a delegated state, MDEQ is required to use the "top-down"

- method. MDEQ follows the Draft 1990 NSR Workshop Manual guidance.
- YES 2. Do you commonly use information resources other than the RACT/BACT/LAER Clearinghouse to identify control options, costs, etc.? If yes, what resources do you commonly use and rate the usefulness of each one?

Answer: The RBLC database is the main resource used to identify control options. Additionally, MDEQ uses other states' permit writers information, as well as Internet information. Based on the data collected, MDEQ developed models for different industries. In the past, for cost analyses, MDEQ used vendor quotes, but today this option is not available anymore, as the vendors are reluctant to release the prices.

YES 3. Do you provide a detailed documentation/explanation of draft BACT determinations in the public record?

Note: MDEQ provides a detailed explanation of the BACT determination in the fact sheet.

YES 4. In your public record for draft BACT determinations, do you provide an economic rationale if a BACT option is rejected as being prohibitively expensive?

Note: MDEQ provides technical and economical rationale of any rejected BACT option, unless the most stringent one is the one that is chosen as BACT.

5. What procedures do you use to calculate baseline emission rates for calculation of cost effectiveness values? What do you view as "uncontrolled" emissions?

Answer: MDEQ uses the worst case uncontrolled emissions from the source for determining the baseline emissions. The baseline is calculated using realistic upper boundary assumptions, taking in account all the documented constraints on the source. The uncontrolled emissions are defined in Rule 121 (Appendix B) as the emissions expected to occur without control equipment, unless such control equipment is, aside from air pollution control requirements, vital to production of the normal product of the process or to its normal operation.

- YES 6. Do you consider combinations of controls when identifying and ranking BACT options (e.g., low organic solvent coatings plus thermal oxidation)?
- YES 7. Do you ever re-group the emissions units included in a cost

evaluation? For example, if an applicant's approach is to evaluate the cost of controlling each unit separately, do you ever consider combining units for control by one control device? Conversely, if an applicant combines all units for control by one control device and concludes this approach is too expensive, do you ever consider controlling individual units or a small group of units that have the greatest percentage of total emissions?

Answer: One permit for which AQD preformed additional BACT cost analysis beyond those completed by the applicant was General Motors - Delta Township, Permit No. 209-00 (Appendix D). The application was for the construction of an entirely new vehicle assembly plant, including a paint shop. Proposed to be included in the paint shop were an electrocoat process (electrocoat dip tank followed by an electrocoat curing oven), a quidecoat process (powder guidecoat booth followed by a cure oven), and a topcoat process (three parallel topcoat spray booths followed by three parallel topcoat curing ovens). Each of the topcoat spray booths includes basecoat zones (both manual and automatic) and clearcoat zones (both manual and automatic). basecoat coatings were waterborne, while the clearcoat coatings were solventbone. Per federal guidance, GM should have provided a BACT cost analysis evaluating control of the entire topcoat process (the basecoat booths, clearcoat booths, heated flashes, and topcoat cure ovens) together. Because GM did not provide such an analysis, AQD preformed the analysis independently as the reviewer.

One permit for which AQD permit preformed the BACT cost analysis according to Director Harding's memorandum of May 24, 2001 was General Motors - Lansing Craft Centre, Permit No. 198-01. This application was to modify an existing automobile and light duty truck coating process. The coating process consists of an electrocoat process (electrocoat dip tank followed by two electrocoat curing ovens), a quidecoat process (a two-section quidecoat booth followed by a cure oven), and a topcoat process (a two-section topcoat spray booth followed by a topcoat curing oven). The two section topcoat booth consists of a waterborne basecoat zone followed by a solventborne clearcoat zone. The modifications made under this application were an increase in allowed production; an increase in allowed VOC emissions; increasing the length and height of the spray booths, the ELPO tank, and the cure ovens to accommodate a larger vehicle profile; a switch to waterborne basecoat coatings; and a change in paint applicators. Per Director Harding's memorandum, the BACT cost analyses were completed on a "single process" basis. For example, the guidecoat manual zone was looked at separately, without grouping it together with emissions from other sources. Had the BACT cost analyses evaluated logical groupings evaluated together, the results of the BACT analysis for this application may have been different in terms of the control

equipment requested.

YES 8. Do your PSD permits specify emissions limits and control methods consistent with the basis (and capabilities) of the selected BACT options?

Note: Both General Motors permit Nos. 209-00 (Delta Township) and 198-01 (Lansing Craft Centre) contained permit conditions to restrict their operations to those determined to be BACT. The permit restrictions include requirements/conditions similar to those listed below -

Pollutant	Equipment	Limit	Time	Compliance	Applicable
			Period	Method	Requirement
					(s)
VOCs	EU-Electroc oat	0.04 Pounds of VOCs Per Gallon of Applied Coating Solids (GACS)	Based upon a Monthly Averaging Period	Condition	R336.1205, R336.1224 R336.1225, R336.1702(a), 40 CFR Part 52.21, 40 CFR Part 60 Subpart MM
VOCs	EU- Electrocoat	30.3 Tons	Per 12-Month Rolling Time Period	Special Condition No. 1.17	R336.1205, R336.1225, R336.1702(a), 40 CFR Part 52.21, 40 CFR Part 60 Subpart MM

- The applicant shall not operate the electrocoat dip tank and/or the electrocoat curing oven portions of EU-Electrocoat unless ELPO Thermal Oxidizer No. 1 is installed and operated properly. Proper operation of the thermal oxidizer includes a minimum VOC destruction efficiency of 95% (by weight), and maintaining a minimum temperature of 1400 degrees F and a minimum retention time of 0.5 seconds.
- All waste coatings and materials shall be captured and stored in closed containers and disposed of in an acceptable manner in compliance with all applicable

state rules and federal regulations.

- The applicant shall operate the electrocoat dip tank such the adequate positive flow of air into the electrocoat dip tank occurs whenever EU-Electrocoat is in use. Positive airflow shall be demonstrated according to a method acceptable to the District Supervisor. In addition, the applicant shall keep all access doors and windows on the electrocoat dip tank closed whenever the electrocoat process is in operation.
- 9. How do you establish the compliance averaging times for BACT emissions limits?

Answer: Michigan Rule 205 (Appendix B) sets the general requirements for emission limits compliance. They include the test methods and BACT (PSD) increments. Any Permit to Install must contains emission limits that are enforceable as a practical matter. The time period is set in accordance with the applicable requirements and, unless a different time period is provided by the applicable requirement, should generally not be more than 1 month, unless a longer time period is approved by MDEQ. A longer time period may be used if it is a rolling time period, but shall not be more than an annual time period rolled on a monthly basis. If the emission limit does not reflect the maximum emissions of the process or process equipment operating at full design capacity without air pollution control equipment, then the permit must contain a production limit or an operational limit.

YES 10. Do you make sure that permit conditions impose restrictions consistent with BACT evaluation assumptions? For example, if the annual emissions used in a BACT cost evaluation are based on an assumption of less than continuous operation and/or operation at less than maximum capacity, do permit conditions contain limits based on the assumption used?

Note: Besides the annual emissions limits, MDEQ also pays attention to permit limits such as seasonal operation, capacity limitations, raw material usage, as well as destruction efficiency or transfer efficiency.

For questions 11-16 regarding BACT cost evaluations:

YES 11. Do you allow deviation from EPA's recommended cost evaluation procedures? If yes, please explain.

Answer: MDEQ allows deviations from cost evaluation guidelines only for companies that can demonstrate the reason. For example, in the

Upper Peninsula, a scrubber used as control equipment can freeze during the cold season.

12. Do you place primary reliance on total or incremental cost effectiveness values? If you give greatest (or equal) weight to incremental costs, what is your basis for doing so?

Answer: MDEQ places primary reliance on total costs, but the incremental cost is taken in consideration, too. There is not a specific number to determine if a cost is effective, but a range of numbers; the cost effectiveness is determined ultimately on a case-by-case basis.

13. Do you place primary reliance on a comparative cost approach or a "bright line" test?

Answer: As all the states in Region 5 do, MDEQ places primary reliance on a "bright zone" instead of a "bright line", because is using a range of numbers, rather than one specific number.

- YES 14. If you place greatest importance on a comparative cost approach, do you try to obtain cost data for projects outside your permitting jurisdiction?
- YES 15. If you use what can be described as a "bright line" test, what is the basis of your "bright line" cost effectiveness value and do you change the value over time to account for inflation?

Answer: MDEQ is using the OAQPS Cost Manual to determine the cost effectiveness. The values are not adjusted for inflation, but other factors such the interest rates are updated.

YES 16. Do you use a different cost approach for different pollutants? If yes, please explain.

Answer: Although uses one model (Cost Manual guidance), MDEQ determines costs on a case-by-case basis, and cost effectiveness is based on the characteristics of each process.

17. Under what circumstances do you conduct a BACT cost evaluation independent of the cost evaluation provided by the applicant? (An independent evaluation could entail obtaining additional vendor quotes.)

Answer: MDEQ does not rely on the applicants' final numbers. MDEQ staff always reruns the cost analysis. Whenever possible, the MDEQ will seek vendors' quotes to verify the costs. However, that has become

increasingly difficult as vendors are unwilling to provide such information due to the unrecouped cost of the effort and the possible ramifications from potential customers. Also, the information is not as reliable as would be perceived as the vendors recognize that they must meet the demands of their current or future customers when providing or not providing equipment. To bolster the review, MDEQ relies upon the available tools of the OAQPS Cost Model, the RACT/BACT/LAER Clearinghouse, and experience with similar operations.

- YES 18. Are cost estimates required to be referenced to a common baseyear (e.g., 1998) so that cost estimates can be easily compared?
- YES 19. Are other agencies contacted to determine if their cost estimates need to be normalized before comparisons can be made?
- YES 20. Do you perform a BACT assessment for all new/modified emissions units or activities emitting a pollutant subject to PSD review no matter how small the emissions from an affected unit or activity?
- YES 21. Do you consider increases or decreases in corollary toxic/hazardous air pollutants as part of a BACT evaluation? [This question addresses implementation of EPA's "North County Resource Recovery Remand" memo dated September 22, 1987.] If yes, please give a specific example.

Note: Based on Michigan specific rule (Rule 225, Appendix B), MDEQ considers T-BACT as part of BACT analysis. An example is the permit for GM Grand River (PTI 134-99B), where the acetone emissions increase was taken into account in the BACT analysis.

YES 22. Do you provide BACT evaluation training to new (or newly-assigned) new source review (NSR) permitting staff (other than on-the-job training)? If yes, describe the nature of the training provided.

Answer: Other than an intensive on-the-job training, the new staff is exposed to any available internal training, and meetings or calls involving BACT evaluation discussions.

YES 23. Do you provide BACT evaluation refresher training to experienced NSR permitting staff? If yes, how frequently do you provide this training and what is the nature of the training provided?

Answer: MDEQ's experienced staff members are required to take updated

permit training. One example is the computerized training in regards to changes to OAQPS model for cost analysis.

YES 24. Do you provide an information outreach program on BACT evaluations for owners of regulated sources? If yes, how frequently do you provide such information and how do you provide it?

Answer: MDEQ provides many opportunities every year for the industry representatives to learn about BACT analysis through workshops, and MDEQ's webpage information (www.michigan.gov/deq, or July 24, 2003 informational letter enclosed in Appendix C that lists the available workshops). One example of these workshops is the October 2003 PSD Workshops; flyers and workbook are enclosed in Appendix E.

- YES 25. Do you provide an information outreach program on BACT evaluations to the public? If yes, how frequently do you provide such information and how do you provide it?
- YES 26. Do you enter each BACT determination in the RACT/BACT/LAER Clearinghouse?
- YES 27. Before establishing BACT as work practice, design, or operational standards do you determine that emissions limits (e.g., lbs/mmBTU, lbs/hr) are not feasible? If no, please explain.
- YES 28. Do you apply BACT to fugitive emissions? If no, please explain.

Answer: Generally, the main two areas for which fugitive emissions are included in the BACT analysis are: chemical plant valves and fittings (MDEQ has not have a NSR permit in the recent past) and fugitive dust material handling plants for the 28 category facilities, which is generally handled with an acceptable fugitive dust abatement plan.

3. Class I Area Protection for PSD Sources

1. How do you determine which proposed projects need a Class I impacts analysis, including consideration of distance of the source from Class I areas (e.g., maximum distance criteria)? Please explain.

Answer: MDEQ considers that the any major project within 100 km from a Class I Area must include a Class I impacts analysis. Currently there are two Federal Class I areas in Michigan: Isle Royale (national park), and Seney (national wilderness area).

YES 2. For new or modified sources within 10 kilometers of Class I areas do you require sources to submit an impact analysis for all pollutants to determine if any have impacts greater than 1 ug/m^3 ?

Answer: For new or modified sources that may affect a Class I area, MDEQ requires any applicant to perform a preliminary analysis to determine whether the source may increase the ambient concentration of any pollutant by $1\mu g/m3$ or more.

YES 3. Do you require applicants to submit a Class I increment analysis for each pollutant subject to PSD review for which an increment exists?

Answer: MDEQ requires applicants to submit a Class I increment analysis (including any necessary cumulative impact analyses) if a significant ambient impact is predicted.

- YES 4. Do you require applicants to identify and provide a cumulative impacts analysis (maximum impact within Class I areas) for all Class I areas impacted by the source?
- YES 5. Do you have a formal procedure for notifying Federal Land Managers (FLMs)? If yes, please explain.

Answer: MDEQ follows the requirements of 40 CFR 52.21 (p) (Appendix B). The department sends the FLM a copy of any advance notification that an applicant submits, and a complete copy of all relevant information within 30 days of receiving it, and at least 60 days before any public hearing on the proposed source.

NO 6. Do your permitting procedures require the applicants to notify Federal Land Managers? If yes, please explain.

Note: MDEQ provides FLM with the information.

YES 7. Is there communication, consultation, and discussion between you and FLMs? If yes, to what extent (e.g, high, moderate, minimal).

Answer: Due to the fact that it rarely occurs, MDEQ staff can't describe the extent. Nevertheless, MDEQ believes in a "pre-application stage", where the applicant, the FLM, and MDEQ meet to discuss about the permit and permitting procedures.

YES 8. Is there communication, consultation, and discussion between the applicant and FLMs? If yes, to what extent (e.g.,

high, moderate, minimal)?

Answer: Although not required by regulation, MDEQ highly recommends and fosters a constant communication between the applicant and the appropriate FLM.

YES 9. Do you actively seek input from FLMs during the permitting process?

Note: MDEQ follows the recommendations from the NSR Workshop Manual (below).

A reviewing agency's policy regarding Class I area impact analyses can ensure FLM involvement as well as aid permit applicants. Some recommended policies for reviewing agencies are:

- not considering a permit application complete until the FLM certifies that it is "complete" in the sense that it contains adequate information to assess adverse impacts on AQRV's;
- recommending that the applicant agree with the FLM (usually well before the application is received) on the type and scope of AQRV analyses to be done;
- deferring to the FLM's adverse impact determination, i.e., denying permits based on FLM adverse impact certifications; and
- where appropriate, incorporating permit conditions (e.g., monitoring program) which will assure protection of AQRV's. Such conditions may be most appropriate when the full extent of the AQRV impacts is uncertain.

In addition, the reviewing agency can serve as an arbitrator and advisor in FLM/applicant agreements, especially at meetings and in drafting any written agreements.

- YES 10. Is the applicant required to address potential adverse impacts on air quality related values (AQRVs) that are identified by the FLM during the notification process?
- YES 11. Do you require prior approval of Class I area impact analysis procedures that applicants plan to use?
- YES 12. Do you require applicants to perform a visibility analysis for Class I areas?
- NO 13.If a visibility impairment is indicated, do you require the applicant to notify the appropriate FLM for the Class I area?

Answer: MDEQ notifies the appropriate FLM.

YES 14. Is the applicant required to address potential effects on scenic vistas associated with Class I areas that may have been identified by the FLM during the notification process?

Answer: Identified in 40 CFR 81, Subpart D, the two Class I areas in Michigan (Isle Royale and Seney) require visibility impact analysis for the integral vista. If the appropriate FLM determines that a proposed source will adversely impact visibility and MDEQ concurs, the permit is not issued. If MDEQ does not agree with FLM, MDEQ has to explain its decision in the notice of public hearing.

YES 15. Do you have a formal process for handling Class I area increment violations if predicted?

Answer: Section 165(d)(2)(C)(ii) of the Act provides that, notwithstanding that the emissions from a proposed facility do not cause or contribute to exceedance of the Class I increment in an area, a permit shall not be issued in any case where the Federal Land Manager of a mandatory class I area demonstrates to the satisfaction of the State that the emissions from the facility will have an adverse impact on the air quality related values(including visibility) of the class I area. If the proposed source would cause or contribute to Class I increment violation, the applicant has to prove otherwise.

- NO 16. Have you issued PSD permits where the FLM objected? If yes, please explain and identify the projects.
 - 4. Additional Impacts Soils, Vegetation, Visibility, Growth
- NO 1. Do your PSD application forms specifically require information regarding additional impacts? If yes, include a copy of the forms.

Answer: In the draft permits, MDEQ includes state Rule 901 as a general requirement. An example in enclosed in Appendix D (Permit 454-96C for Ford Motor Company): this permit's General Condition 6 states that operating the source cannot result in the emission of an air contaminant which causes injurious effects to human health or safety, animal life, plant life of significant economic value, or property, or which causes unreasonable interference with the comfortable enjoyment of life and property.

- YES 2. If no, do you require applicants to submit sufficient information necessary to complete an additional impact analysis?
 - 3. What resources do you use for researching additional

impacts?

Answer: MDEQ uses toxicological and vegetation data, as well as expert opinions on local soils and vegetation.

YES/NO 4. Do you include environmental justice and/or endangered species issues in your analysis?

Answer: Although MDEQ does not specifically include EJ and endangered species issues in a permit analysis, it allows an "enhanced review" of a permit application, sometimes with additional opportunities for the public to comment or to express their concerns.

YES 5. Has an additional impact analysis in the last 5 years been a cause for concern in an issuance of a PSD permit? If yes, please explain.

Answer: In the case of the facilities below MDEQ looked at the blood lead level when issuing the permits.

<i>Genesee Power</i>	1995
Central Wayne	1997
Select Steel	1998
City Medical	1999

YES 6. Do you generally allow arguments that the protection of the NAAQS will assure protection of vegetation? If yes, please explain.

Answer: Generally, MDEQ finds sufficient the secondary standard for NAAQS as an adequate demonstration for protection of vegetation and soils. However in one case, Cadillac Renewable Energy 373-86C, the analysis included EPA 450/2-81-078 "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals: Final Report" established ambient concentrations for SO2 to indicate insignificant impact.

- YES 7. Do you require that predicted short-term impacts (e.g, one hour NOx impacts) be used to assess impacts on vegetation for pollutants which do not have short term ambient standards? If no, please explain.
- NO 8. Regarding visibility impacts, do you require assessments for vistas (e.g., parks, airports) near the proposed source or modification? If no, please explain.

Answer: Generally, MDEQ requires assessments for vistas only for Class I areas.

5. Preconstruction Monitoring

NO 1. Do you have formal preconstruction monitoring requirements?

Answer: Although MDEQ does not require preconstruction monitoring for each permit, the permit writers use available monitoring data to verify if the predicted ambient impact or the existing ambient pollutant concentrations are less than the prescribed significant monitoring concentrations (as defined in 40 CFR 52.21 (i)(8)(i)).

- N/A 2. Do you have a formal public participation process regarding requirements for preconstruction monitoring for specific proposed projects?
- N/A 3. Have you ever consulted with FLM regarding preconstruction monitoring requirements for a proposed source or modification?
- NO 4. In the last five years have you ever required an applicant applying for a PSD permit to conduct preconstruction ambient monitoring or meteorological monitoring?

Answer: MDEQ recalls one preconstruction monitoring required for a PSD permit (Champion Corporation, in the 1980s).

NO 5. Do you have a formal approval/denial process at the conclusion of preconstruction monitoring?

Note: MDEQ has an informal process. The approval/denial process at the conclusion of preconstruction monitoring is part of the PSD permitting process.

- N/A 6. Do you have a formal process during preconstruction monitoring for resolving conflicts between the FLM and the applicant? If yes, please explain.
- YES 7. Do you routinely provide ambient monitoring data in lieu of requiring applicants to perform preconstruction monitoring?

 If yes, please briefly describe the monitoring network used and the basis for the monitoring value selected.

Answer: MDEQ uses AIRS database for the most representative data; the values include emission inventory, background check, and state borders.

YES 8. Do you follow EPA guidance (e.g., siting, equipment, data validation, audits) regarding collection of

preconstruction monitoring data?

9. Under what circumstances would you require post construction ambient monitoring as a condition of a PSD permit?

Answer: MDEQ requires post construction monitoring if the NAAQS are threatened, or there are uncertainties in the data bases for modeling. One example is Zeeland Farm Inc (PTI 479-95A) where post construction modeling was required because the source was in danger to violate the PSD increments.

6. Increment Tracking Procedures

1. What method do you use to assign baseline dates, e.g., county-specific, region-specific, or entire state?

Answer: MDEQ uses region-specific method to assign baseline dates.

- YES 2. Do you have a list of the minor source baseline dates for each area?
- YES 3. Do you have an understanding of receptor location dependence vs. source location dependence for increment tracking?
 - 4. Do you have a formal or informal program for increment tracking?

Answer: MDEQ is informally tracking the increment consumption, based on the baseline and permit application data.

- YES 5. Do you maintain and update a computerized emission source database for increment tracking that includes minor sources that affect increment? If yes, does the database include the information needed for modeling (e.g., source locations, stack parameters, emissions)?
 - 6. Do you use allowable or actual emissions for increment tracking purposes? If actual emissions, how do you calculate emissions for each averaging period covered by the increments?

Answer: MDEQ uses both, allowable and actual emissions, depending on the source. For the permitted sources, allowable emissions (PTE) are used, and for sources that are not permitted, actual emissions are used (by determining hourly emissions: tons per year divided by 8760 hours per year).

- NO 7. Are area sources included in increment tracking analyses, e.g., growth-related and transportation-related emissions?
 - 8. How frequently is increment consumption evaluated on a scheduled basis or just when occasioned by a new permit application?

Answer: MDEQ evaluates the increment consumption when a permit application is received.

9. How "transparent" (i.e., understandable) is the emission source inventory used for PSD modeling? Could an outside reviewer (such as a member of the public) clearly identify the sources included (e.g., name, location, stack parameters) and the sources excluded in a modeling analysis?

Answer: The emission source inventory is developed to be easily understood by the citizens.

10. How do you handle interstate increment tracking (for state reviewing authorities) or interjurisdiction tracking (for local reviewing authorities), including consistency of tracking across jurisdiction boundaries?

Answer: MDEQ is making any necessary efforts to have a good working relationship with the neighboring states and Canada. This includes notifying the affected state of any permit applications, and dialogs related to the permit or permitting issues involved. Although in the past Canada was not regularly discussing environmental issues with the American counterparts, now there are current commitments from both sides to build a stronger relationship with respect to the NSR permits. For example, an informational meeting with MDEQ, Environment Canada, and EPA Region 5 representatives was scheduled for Spring 2004.

11. What procedure do you follow in planning for and incorporating new modeling tools?

Answer: The air modeling team can develop new modeling tools based on the federal guidance and existing models (for example AERMOD, a national screening model, is currently in the development stage, and MDEQ is involved in the process)

YES 12. Do you provide increment tracking training to NSR permitting staff (other than on-the-job training)? If yes, describe the nature of the training provided.

Answer: The nature of training for the permit engineers and modeling staff is described below:

Permit Engineers - part of general PSD training which include:

- EPA courses and workshops
- State PSD training
- On-the-job PSD training

Modeling Staff - part of NSR modeling training

- National modeling workshops
- On-the-job

7. Endangered Species Act (ESA)

- NO 1. Do you have a PSD program that is fully approved by EPA (i.e., SIP-approved?
- YES 2. Do you have a fully or partially-delegated PSD program?

 (Note: ESA obligations apply only when all or portions of a PSD program have been delegated.) If yes, answer questions 3 through 6 below.
- NO 3. Do you notify PSD permit applicants of their ESA obligations?

 If so, please provide a copy or description of your notice.

Note: MDEQ stated they have not encountered instances when a PSD had ESA implications.

- NO 4. Do you know the difference between a formal vs. an informal consultation process?
- NO 5. Do you advise applicants, concerning their ESA obligations, to consult with a.) EPA; b.) The U.S. Fish and Wildlife Service; and/or c.) Federal Land Manager? If yes, please explain, and describe what information you provide to applicants concerning their ESA obligations.
- NO 6. Does an ESA consultation affect the timing of your issuance of a proposed or final PSD permit? If yes, please explain.

III) Nonattainment NSR

At the time of the audit Michigan had no non-attainment areas. Prior to the audit MDEQ and EPA agreed that it was inappropriate and counterproductive for these questions to be answered. The audit captured a moment in time - July 21 and 22, 2003. At that time, MDEQ did not have a confident working knowledge of the non-attainment permitting process as the entire state of Michigan had been in attainment for all pollutants since 1999 and there were no non-attainment NSR applications in over five years. Furthermore, there was a large lag time before the designation of non-attainment areas and the release of the ozone and PM2.5 implementation rules outlining the approach Michigan must take. It was recognized by all that prior to the re-designations taking effect, significant training of staff on the Clean Air Act requirements, Appendix S requirements, new ozone and PM2.5 Implementation Rules, State Rules and any EPA guidance regarding non-attainment permitting would be needed. training occurred after the July 21 and 22, 2003 audit.

IV). Minor NSR Programs

1. NAAQS/INCREMENT Protection

- YES 1. Do you use modeling to assure that minor sources and minor modifications will not violate the NAAQS?
- YES 2. As a result of modeling are air quality monitors required for some sources as a permit condition?
- YES 3. For the pollutants with PSD increments established do you have a list of areas where the minor source baseline has been triggered?
- YES 4. Do you model minor sources for PSD increments if the minor source baseline is triggered?
- YES 5. Do you have procedures in place to identify minor sources that consume or expand PSD increment?
 - 6. How does the public access a list of sources that affect PSD increments?

Answer: The public has access to the list of sources that affect PSD increments through a FOIA request.

2. Control Requirements

YES 1. Does your SIP require any level of control for emissions units not subject to major NSR requirements (e.g., BACT or LAER)? For example, do you have a BACT or similar requirement for minor modifications?

Answer: For the emission units not subject to major requirements MDEQ requires different levels of control, established by the T-BACT (or toxic BACT) analyses, minor sources BACT analyses for VOC and PM, sulfur requirements, as well as the applicable rules R336.1801 and R336.1802, establishing NOx emission limitations from stationary sources (enclosed in Appendix B). It would not be very often that a minor source would come under these latter rules.

YES 2. Are there any monitoring or reporting requirements for minor sources?

Note: MDEQ requires periodic monitoring for all types of emission units.

- YES 3. Does the application or permitting process require modeling for minor sources?
- YES 4. Do you require minor sources with Federally applicable permit limits for MACT, NSPS, or NESHAP to report compliance?

Answer: The requirement is one of the General Conditions in every permit (Rule 207, enclosed in Appendix B). Rule 207 states that MDEQ will deny an application for a permit to install if the equipment for which the permit is sought will not operate in compliance with the rules of the department or state law, the operation of the equipment for which the permit is sought will interfere with the attainment or maintenance of the air quality standard for any air contaminant, or the equipment for which the permit is sought will violate the applicable requirements of the clean air act; also, if sufficient information has not been submitted by the applicant to enable MDEQ to make reasonable judgments, the permit application would be denied.

In addition, specific industries (such as the asphalt portable plants) are required to have more controls through T-BACT analyses, HAPs testing, PM or CO limits.

V. Public Participation

1. Public Notification

1. What criteria are used to determine if a permit is public noticed?

YES Are new nonattainment NSR and PSD permits noticed?
YES Are major modifications noticed?
YES Are synthetic minor permits noticed?

YES Are netting permits noticed? YES Are minor permits noticed?

Other?

Answer: MDEQ public notices all the controversial permits, regardless of the PTE status, and also all the sources exceeding 90% of the applicable threshold.

YES 2. Do you publish notices on proposed NSR permits in a newspaper of general circulation?

Note: MDEQ uses at least two daily local newspapers, and a weekly newspaper.

YES 3. Do you use a state or other publication designed to give general public notice? If yes, please describe.

Answer: MDEQ uses the Internet (http://www.michigan.gov/deq), along with the department's newsletter, "Calendar", online and hard copy publication, (enclosed copy, Appendix E), direct mailing lists to Canada, affected states, concerned citizens, and local government organizations.

YES 4. Do you have procedures for notifying the public when major NSR permit applications are received?

Note: MDEQ usually posts relevant information on the website.

YES 5. Have you developed a mailing list of interested parties for NSR permit actions [e.g., public officials, concerned environmentalists, citizens]? If yes, how does one get on the list?

Answer: MDEQ adds a name on the list upon request, usually at the public

hearings.

YES 6. Aside from methods described above, do you use other means for public notification? If yes, what are they (e.g., post notices on your webpage, email)?

Answer: MDEQ uses the webpage as a mean for public notification (see enclosed July 24, 2003 letter, Appendix E).

YES 7. Do your public notices clearly state when the public comment period begins and ends?

Answer: MDEQ clearly states in the "Notice of Air Pollution Comment Period and Public Hearing" when the comment period starts and ends, basic information about the company, as well as information about the public hearing. An example of public notification notice is enclosed in Appendix D (PTI 114-03 for Fairmount Minerals).

8. What is your opinion on the most effective ways to provide public notice?

Answer: MDEQ feels that the best most effective way to provide public notice is through the Internet (webpage).

NO 9. Do you provide notices in languages besides English?

Answer: Although MDEQ does not provide translation of the notices, the non-English speaking citizens can obtain translated information by calling the office. MDEQ's webpage contains these info in different languages.

YES 10. Have you ever been asked by the public to extend a public comment period? If yes, did you grant the extension? If no, please explain?

Answer: MDEQ is usually granting the extension requests based on need (for example for citizens that just found out about the project, or if, during the public period not all the information were available for the public, or due to natural causes, the public hearing cannot be held; a notification example of an extended comment period for Minergy Detroit, June 12, 2003 is enclosed in Appendix E.

11. What approximate percentage of your major NSR permits are revised due to public comments? Remands? State appeals?

Answer: MDEQ staff feels that 40-50% of the permits are revised due to the comments (mostly changes on testing, recordkeeping, and monitoring), and only a very few changes were made due to remands or

appeals.

12. If a draft permit is revised, what criteria do you use to determine if a permit should be re-issued in draft?

Answer: MDEQ considers re-drafting a permit only if the comment resulted in a major change to the permit (such as appreciable increase in emission rate, or significant changes in terms and conditions of the permit).

13. What type of comments or other concerns trigger a public hearing?

Answer: Any concerned citizen or organization can request a public hearing. If there is a general concern, MDEQ holds an informational meeting before the public hearing.

14. How are public hearings noticed? How much notice is given?

Answer: As mentioned in the answer to question 7, MDEQ uses a joint notification for public hearings and public comment period. The minimum time for noticing the public is 30 days. An example is enclosed in Appendix E, for Fairmount Minerals, PTI 114-03.

15. What is your process for the public to obtain permit-related information (such as permit applications, draft permits, deviation reports, monitoring reports) especially during the public comment period?

Answer: The public or any interested party can find the permit related information through a FOIA request, MDEQ webpage, mass mailing, and inquiries to the local government. Sometimes copies of the files are available at local public libraries. The permit applications are available upon request as hard copy at MDEQ office.

YES 16. Do you have a website for the public to get permit-related documents? What is available online? How often is the website updated? Is there information on how the public can be involved?

Answer: The online info contains the public notice, the fact sheet, the draft permit, and contact information (see enclosed printed copy of the NSR Public Notice Documents, Appendix E). For the last 2 years the website info is updated almost daily. The permit applications are not available electronically yet. The public is also notified about the opportunity to be involved in the process through the letters to all who submitted comments and previously attended public hearings.

YES 17. Do you provide training to citizens on public participation or on NSR? If yes, approximately how many training opportunities have been provided in the last five years.

Answer: MDEQ provided numerous training opportunities to the public through various NSR workshops (at least 4/year). Specific training information is also available in MDEQ webpage.

18. How do you notify affected States (including tribes and Canada) of draft permits?

Answer: MDEQ notifies affected States though emails and direct mail.

YES 19. Do public notices for PSD permits specifically state the amount of increment consumed?

Answer: MDEQ notifies the public that the permit is not violating the NAAQS and would not exceed available increments (in percentage). An example of public notice is enclosed (Quanex Corporation, PTI 535-96G), in Appendix D.

YES 20. Are public notices for PSD permits sent to each party identified in 40 CFR 51.166(q)(2)(iv)?

2. Environmental Justice (EJ)

- Note:

 By EJ analysis we refer to any procedures applied during the permitting process, regardless of whether they are called EJ, that consider demographics (race, income, nationality, etc.), cumulative effects (burden, exposure, risk), comparative effects or modifications to the public involvement processes to address unique characteristics of the project.
- YES 1. Do you consider EJ issues during the permitting process? If yes, please provide a description of the criteria, guidelines, or screening procedures used to address EJ issues.

Answer: MDEQ considers EJ issues (or "enhanced reviews") during a permitting process. In these reviews MDEQ takes in account cumulative effects of pollutants and performs risk assessments. MDEQ provides sufficient and extensive public notification.

N/A 2. Regarding section 173(a)(5) of the Clean Air Act, do you conduct an alternatives analysis as part of your nonattainment area permitting process? If yes, please provide a description of the EJ criteria or guidelines used

for this analysis.

Answer: At the time of the audit MI was designated as attainment area. Nevertheless, State Rule 220 (1)(d)(Appendix B) requires specific sources to prove that "the benefits of the proposed major offset source or major offset modification significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification".

- YES 3. Regarding section 165(a)(2) of the Clean Air Act, does your NSR permitting program and public comment process for PSD regulated pollutants provide for consideration of alternatives?
 - 4. How are the demographics of the affected community taken into account in the permitting process?

Answer: The demographics are not taken in consideration in the permitting process.

5. How are cumulative effects and/or pre-existing burden addressed in the permitting process?

Answer: MDEQ does not issue permits for sources that affect the health and welfare of the citizens. In the permitting process, MDEQ includes modeling and tests on the background emissions levels.

6. What additional community information and/or demographics (for example - children, the elderly) do you consider important for an EJ analysis?

Answer: MDEQ takes in consideration risk factors for elderly and children, as well as hospital statistics and information.

- YES 7. Do you allow public involvement during an EJ analysis? If yes,
 - a. What stakeholder groups do you try to involve?

Answer: MDEQ takes in consideration the input from any interested party (usually environmental groups and citizens).

b. At what point in the EJ analysis or permitting process do stakeholders become involved?

Answer: MDEQ advises companies going through large projects to involve interested citizens or environmental groups early on the process.

c. To what degree and in what manner do stakeholders or the community influence the permit decision making process?

Answer: The shareholders and communities can influence the permit decisions through the comments made during the public comment period.

d. To what degree do you know about how stakeholders or the affected community participated in the permit decision making process?

Answer: MDEQ encourages any applicant to involve the citizens and the public in general, in the process. To facilitate this, MDEQ assigned engineers set up meetings with the company and interested parties. One example is Ford Company and Access (an environmental citizens group), where the company informs the organization about projects and deadlines.

e. Describe how you make information available to stakeholders and the affected community. (For example - translation of information, understandable and accessible materials, personal contacts, clearly explained technical information including potential risk, distribution of information, public meetings, etc.)

Answer: MDEQ makes the information available to public through many channels: libraries, direct mailing, informational meetings, newspapers, and, as much as possible, on the MDEQ's webpage. One example of the public notification efficiency is the meeting for a Cadillac permit (year 2000), where 600 people attended and submitted comments.

- NO 8. In the EJ analysis, do you consider direct and indirect benefits and burdens from the proposed actions? If yes,
 - a. Describe what benefits you consider in the EJ analysis. (For example economic, social, cultural, health, environmental, etc.)
 - Describe what burdens you consider in the EJ analysis.
 (For example economic, social, cultural, health, environmental, etc.)

Answer: In the EJ analysis, MDEQ takes in consideration only the environmental impacts.

NO 9. In the EJ analysis, do you consider comparative and

disproportionate impacts? If yes,

- a. Describe the criteria or procedures used to determine any potential or actual adverse health or environmental effects or impacts.
- b. Describe the criteria or procedures used to determine whether evidence exists to describe these effects or impacts.
- c. Describe the criteria or procedures used to determine whether the proposed project complies with all applicable environmental laws.

VI). Program Staffing and Training Issues

1. What is the total number of staff dedicated to permitting for your NSR program? Please provide an organizational chart.

Answer: In 2003, the Permit Section had approximately 25 permit engineers, 5 supervisors, 4.5 implementation (engineers and analysts) staff, and 2.5 clerical support staff. One additional position had been vacant for over a year (total 39 people/38 Full Time Equivalent Positions). There is a number of other staff within the Division that works on NSR permits, as needed. The organizational chart is enclosed (Appendix C).

2. For your NSR program please breakdown the staff into the different job functions (e.g., number of modelers, review engineers, technicians, environmental scientists, clerical, supervisory, enforcement).

Answer: The NSR program staff members are divided into different job functions as follows:

Engineering Supervisors	5
Clerical	2.5
Department Analysts	2
Environmental Engineers	28.5
Environmental Quality Analysts	7
Other (modelers, lab scientists, toxicologists)	5
Total 50 positions -	- 52 employees

In FY 02, approximately 23 out of 40 staff positions were funded by fees. The balance was funded by Section 105 grant and related general fund match and general funds.

3. Please describe your training program for new and existing staff who work on NSR permitting and issues. List any materials you use or training course you try to attend.

Answer: The new and existing employees training program is establish at the beginning of each year. Appendix E includes the 2002 training schedule and program. The 2002 training schedule for NSR permit engineers gives detailed information about the subject (e.g. CAA, PM Permits, or Combustion), the time and the trainer. Employee training plan is a more general plan that defines the recommended and elective training sessions for new employees of different units within MDEQ for a 2-year period.

4. Describe any additional training that you believe would be beneficial. Would you like for EPA to provide more NSR training?

Answer: MDEQ staff feels that an additional NSR Reform training would be helpful.

YES 5. Do you provide NSR program training opportunities for the public, including the regulated community? If yes, please describe.

Answer: MDEQ provides monthly PTI Workshops in various locations for citizens, environmental groups, and regulated communities (enclosed 2003 flyers, in Appendix E).

6. Total number of staff w/ 3(?) years or more of experience" 5 yrs? 10 yrs?

Answer: In 2003, the number of MDEQ employees with less than 3 years experience was 6, with 3-5 years experience was 3, and 5-10 years experience was 10. There are 33 employees with more than 10 years work experience (total 52 employees).

VII). General NSR Program Issues

- YES 1. Do you implement EPA issued program guidance and policy for NSR? In no, please explain.
 - 2. In general, how do you learn about federal NSR rule changes? Do you use EPA's TTN website at www.epa.gov/ttn to monitor NSR program changes and implementation issues? Do you find the info on the TTN adequate? Is there any other information you would like to see provided?

Answer: MDEQ staff finds out about federal rule changes through direct mail from US EPA, state calls, TNN webpage, or reform guidance. Each of the above sources, independently, may not be enough.

3. How do you determine if emissions factors (e.g., AP-42) are acceptable for NSR applicability purposes?

Answer: MDEQ determines if emission factors are acceptable on a case-by-case basis. This includes relying on stack tests performed at that facility or on similar operations, continuous emission monitoring data, the FIRE database, the RACT/BACT/LAER Clearinghouse, other reported emission factors, and Michigan's emission reporting database.

4. Please provide any comments, suggestions, or concerns you may have regarding the NSR program.

Answer: MDEQ engineers feels that one concern is the inconsistency of program application across the regions.

5. Please provide the number of non-major permits you issued last year.

Answer: In 2002, MDEQ issued about 450 non-major permits. Since 1993, 1450 permits were issued.

6. How many PSD permits did you issue last year?

Answer: MDEQ issues an average of 15 permits each year (including last year).

7. How many nonattainment NSR permits did you issue last year? Since 1990?

Answer: At the time of the audit Michigan was considered attainment area. There is no centralized database to count the number of NAA NSR

permits issued before the attainment area designation.

8. For PSD permits what is the average time (months) taken by you to issue the permit, starting from the time the application was determined complete? For nonattainment NSR permits?

Answer: At the time of the audit Michigan was considered attainment area. For the PSD permits, the average time to issue a permit depends on the type of source and complexity of the permit. For example, for auto assembly plants, it takes an average of 32 days to review (68 days to issue), and for non-auto sources, about 109 days (160 days to issue). Usually it takes a long time for the company to review the draft permit conditions. This time was not included in the above average time. Including this time, it takes 384 days to issue an auto source permit and 363 days for non-auto sources. For more details see enclosed Tables K1 and K2, in Appendix C.

YES 9. Do you have a formal procedure for establishing past permit violations related to NSR requirements?

Note: MDEQ uses an enforcement database and established formal inspection procedures based on the enforcement policy.

- YES 10. Do you have a formal procedure for dealing with "self reported" NSR violations?
- YES 11. Do you have formal enforcement procedures for dealing with past violations of NSR requirements, including applicable BACT or LAER requirements of major NSR?
- YES 12. Do you include PM10 condensible emissions in the total amount of PM10 emissions when determining PSD applicability, BACT, PSD increment, and NAAQS?
- YES 13. When PM10 testing is required do you include a permit condition that requires testing and specifies testing methods for PM10 condensibles?"

VIII). Effective Construction Permits

General Comment: MDEQ believes they do incorporate all of the criteria below in their permits. As a list of examples, MDEQ provided the entire list of permit applications public noticed and issued in the calendar year 2003 (Table VII. 1). All of these have been sent to the regional office as part of the public noticing process.

TABLE VII. 1

COMPANY NAME	PTI #	END of COMMENT PERIOD	HEARING HELD	REASON
SUMPTER ENERGY	62-01A	12/22/03		PSD
QUANEX CORP	535-96 G	12/5/03		PSD
GEORGIA-PACIFIC	57-02	12/5/03		DENIED, state rules
CENTRAL WAYNE (COMBO CONSENT ORDER)	190-95 A	12/1/03	YES	PSD
GM POWERTRAIN SAGINAW	109-03	11/14/03		PSD
GUARDIAN FIBERGLASS (COMBO ROP)	282-02	11/5/03	YES	PSD
LOUISIANA PACIFIC	41-03	10/13/03		PSD
ABBOTT LAB-ROSS PRODUCTS	64-03	9/15/03		PSD
DTE ENERGY CONNERS CREEK	114-99 A	8/22/03		PSD
ANR PIPELINE	35-03	8/14/03		PSD
DEARBORN INDUSTRIAL (DIG)	253-02 A	8/4/03	YES	Netting
MINERGY	175-00 A	7/29/03		PSD
GENERAL PERMIT PROPANE OR NATURAL GAS FIRED BOILERS		7/28/03		Rule requirement
SPARTAN STEEL	423-95 A	7/24/03		Synthetic minor
GENERAL PERMIT NATURAL GAS FIARED BURNOFF OVEN		7/23/03		Rule requirement
HOLCIM	60-710	7/22/03	YES	Controversial
CADILLAC RUBBER & PLASTICS	286-02	6/27/03		Synthetic minor
YCUA	68-02	6/24/03	YES	Controversial
UNIVERSAL COATING	177-96 B	6/11/03	YES	Controversial
EATON PROVING	34-98A	6/2/03		Synthetic minor

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	KALKASKA GENERATING	119-02	12/19/02	PSD

^{*} Multiple stationary sources redefined to establish one and confirm reissued permit complies with all previous PSD and LAER determinations and requirements.

More general information is enclosed in Appendix C ("Overview of the NSR Process" and "MDEQ Standards").

Do your construction permits:

- YES 1. Identify each emissions unit regulated?
- YES 2. Establish emissions standards or other operational limits that must be met, including appropriate averaging times for numeric limits?
- YES 3. Include specific methods for determining compliance and excess emissions, including reporting, record keeping, monitoring, and testing requirements?

- YES 4. Outline procedures necessary to maintain continuous compliance with emission limits?
- YES 5. Establish specific, clear, concise, and enforceable permit conditions?
- YES 6. Include conditions necessary for a source to avoid otherwise applicable requirements (e.g., keeping a modification "minor")?
- YES 7. Do you use statements of basis for construction permits?

IX). Reform Questions

1. Program Implementation

- YES 1. PSD Delegated States: Are you fully implementing the new PSD provisions that went into effect on March 3, 2003? If not, what provisions are not being implemented? Why?
 - 2. PSD SIP-approved States and nonattainment NSR: Are you currently developing rulemaking to adopt the 3/3/03 provisions? What is your timeline for adoption? Does this include changes to minor NSR regulations?c

Answer: MDEQ is currently developing rulemaking to adopt the 3/3/03 provisions, but they are also considering all options, with the evolving lawsuits. The timeline for adoption is presently targeting Early 2005. This does not include changes to minor NSR regulations.

2. Previous Experience with Provisions

YES 1. Have you granted any PCP exclusions prior to the new regulations (pursuant to the 7/1/94 EPA policy memo or the WEPCO rules)?

Note: MDEQ granted 3-4 PCP exclusions/ year.

2. Have you made PSD/NSR applicability determinations based on a past actual vs. projected future actual test (WEPCO)? If Yes, how do you track future actual emissions?

Answer: MDEQ made PSD/NSR applicability determinations based on a past actual versus projected future actual test. The actual emissions are tracked in permit conditions, and recorded from inspections at the sources.

NO 3. Have you issued any PAL permits?

3. New Provisions

YES 1. Have you received permit applications requesting any of the new NSR provisions? If yes, please explain.

Answer: MDEQ received 5 permit applications requesting new NSR provisions (below). The application forms are not changed.

- Holcim, 60-710, used past actual to future actual test, issued
- Detroit Edison, 158-03 & 159-03, clean unit designations, issued

- Marathon Ashland Petroleum, 262-02, netting, soon to go out for notice
- Dow Chemical, 251-03, netting, application being processed

YES 2. Have you provided training to your staff on the new NSR provisions?

Answer: MDEQ is committed to training not only own staff, but also other states (MPCA, Minnesota Pollution Control Agency), the public (regulated communities), industries (such as Michigan Manufacturing Association), and other interested parties.

VIII. File Review

The file review part consisted of 30 minutes review of each of the following type of permits: a PSD permit with a BACT analysis, a synthetic minor permit, a net-out permit, and a controversial permit. The choice of the permits was at MDEQ's discretion, and the permits chosen were:

- A.Dearborn Industrial Generation, issued 2000
- B.Continental Aluminum (controversial permit), issued 2001
- C.Delphi Saginaw Steering Systems (opt-out permit), issued 2002
- D.El Paso Merchant Energy (PSD permit), issued 2002
- E.Daimler Chrysler Corporation (Opt-out, synthetic minor permit), issued 2003

Files Summary

A. Dearborn Industrial Generation, final permit issued in 2000

The permit for Dearborn Industrial Generation is an example of a PSD permit for a pollutant and a netting out example for another pollutant.

The file contains a chronologically organized set of documents, starting with the permit application information, including the technical documentation, air quality data and evaluation form, the draft permit (July 1999), the final permit (October 1999), and the responses to the comments made during the public comment period and public hearing. It also includes the correspondences between MDEQ and the public (citizens, citizen groups and environmental groups), phone calls logs, and summaries of internal meetings.

B. Continental Aluminum Company, final permit issued in 2001

The permit for Continental Aluminum Company (PTI 504-96B) is an example of a controversial permit. In the permit application the company requested process modification to their existing secondary aluminum processing facility. These modifications, and a consent order, that required the payment of a civil penalty, were to resolve prior air quality violations at the facility.

The file contains the permit application, draft and final permits (including the changes made due to the comments), public participation documents, charts identifying significant dates, the consent order, compliance issues, the compliance program, with the scrap inspection and malfunction plans. It also contains the email communications, summaries of internal meetings, and documentation provided at the hearing.

C. Delphi Saginaw Steering Systems, final permit issued in 2002

The PTI No. 143-02 for Delphi Saginaw Steering Systems is an example of an "opt-out" permit. The applicant proposed to relocate an existing natural gas-fired boiler from one plant to another. The facility took restrictions on fuel usage, and therefore was not subject to the federal PSD requirements.

The permit's file contains a good chain system, including the initial priority dates, staff responsible, and all the appointment dates. It also contains the public notification, public participation documents, newspaper announcements, the fact sheet, general conditions (including a general review of the permit conditions, and approval cover letter), and draft and final permits, with detailed emission calculations. Additionally, the file includes all the correspondences, phone calls logs, and contact information.

D. El Paso Merchant Energy, final permit issued in 2002

MDEQ chose the PTI 185-01 for El Paso Merchant Energy as the example for a PSD permit. The permit is for installation of a 510 MW electric generating plant consisting of three natural gas-fired combustion turbines.

The file contains a complete public participation documentation (public notification, public hearing information, response to comments according 40 C.F.R. 124.17, along with MDEQ contact information). The control technology review included the correspondences between the company and MDEQ, and complete research material for the BACT analysis. Generally, the file includes all the correspondences, phone calls logs, and contacts information.

E. Daimler Chrysler, final permit issued in 2003

Daimler Chrysler proposed through PTI 261-99A to limit the fuel use to restrict NOx and CO emissions from the entire facility below major source thresholds. The file contains complete public notification information, along with the technical documentation, and the fact that no comments were received. Because initially the permit was received by Wayne County MDEQ, Air Quality Management Division (dissolved in 2001), and then reassigned to MDEQ Detroit Office, the file contained in the General Comments the Timeline and Phonelog, with all the MDEQ engineers involved in the permitting process.

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,)	Civil Action No. 2:10-cv-13101-BAF-RSW
and) NATURAL RESOURCES DEFENSE) COUNCIL, and SIERRA CLUB)	Judge Bernard A. Friedman Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors) v.)	
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)	
Defendants.)	

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 6

IN RE TENNESSEE VALLEY AUTHORITY

CAA Docket No. 00-6

FINAL ORDER ON RECONSIDERATION

Decided September 15, 2000

Syllabus

This proceeding concerns an administrative compliance order, as amended (the "Compliance Order"), EPA Region IV issued under the Clean Air Act ("CAA") to the Tennessee Valley Authority ("TVA"). EPA Administrator Carol M. Browner asked that the Environmental Appeals Board ("Board") reconsider the Compliance Order and issue the Agency's final decision on reconsideration.

TVA, an agency of the United States government, owns and operates eleven coal-fired electric power generating plants, many of which contain more than one generating unit. Most of TVA's power plants were built between the early 1950s and the early 1970s. The Region has alleged that TVA violated the CAA when it made certain changes to four-teen coal-fired electric power generating units at nine of TVA's plants without first obtaining preconstruction permits from either the EPA or, where applicable, the appropriate State or local agency. The projects took place between 1982 and 1996.

The CAA establishes two types of new source review ("NSR") preconstruction permitting programs relevant to this case: the prevention of significant deterioration ("PSD") program applicable in areas with air quality that is better than the national ambient air quality standards, and the nonattainment new source review ("nonattainment NSR") program applicable in areas with air quality that does not meet those standards. The PSD and nonattainment NSR permitting programs are run either by the EPA or, if a state has obtained EPA approval of a state implementation plan ("SIP"), by the applicable state or local agency. There is also a third type of preconstruction permitting program created pursuant to some of the state's SIPs, known as a minor NSR permitting program. In the present case, TVA's plants were, at various times, subject to the federal permitting regulations and at other times subject to SIP permitting programs run by the States of Alabama, Tennessee, and Kentucky, and a local program run by the Memphis-Shelby County Air Pollution Control Board in Tennessee. The CAA's new source performance standards ("NSPS") requirements are also relevant to this proceeding.

The CAA's NSR permitting and NSPS requirements are intended to assure that major sources of air pollution use appropriate controls to limit the emission of pollutants into the atmosphere. All of TVA's coal-fired power plants at issue in this case were originally designed and built before the CAA was amended in 1977 to require persons who own or operate certain facilities that are sources of pollutant emissions to obtain preconstruction permits.

Congress did not require existing pollution sources to install immediately the pollution controls the Act requires for new sources of air pollution. Instead, Congress provided that existing sources would become subject to the CAA's requirements when these sources are "modified." Thus, the term "modification" is a key term used in the CAA to identify whether a source must comply with one or more of the CAA's preconstruction permitting programs.

The central question presented is whether changes undertaken by TVA were "modifications" for which TVA was required to obtain preconstruction permits. (The term "modification" is also relevant for determining whether two of TVA's units became subject to the NSPS requirements as a result of the changes to those units.) As relevant here, the CAA definition of "modification" contains two primary parts: (1) there must be a *physical change* at an emissions source, and (2) the change must result in an *emissions increase* at that source.

The regulations EPA adopted to implement this statutory two-part test establish certain exclusions from what would otherwise be considered "physical changes." At the heart of the dispute in this case is an exception the regulations provide for "routine maintenance, repair and replacement." The regulations also establish detailed requirements concerning whether a physical change results in an emissions increase. There are generally different methods under the NSPS and the NSR programs for determining whether a change results in an emissions increase.

The Compliance Order alleged that TVA made "physical changes" to the fourteen coal-fired generating units and that those physical changes caused emissions increases for nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM) sufficient to trigger the applicable permitting requirements. TVA raised a variety of objections to the Compliance Order, including that the changes at issue fall within the exception for routine maintenance, repair and replacement and that the Agency's enforcement personnel prosecuting the case before the Board ("EPA Enforcement") failed to show that the changes caused emissions increases sufficient to trigger the permitting requirements.

Held:

The Compliance Order is sustained in part and vacated in part. EPA Enforcement has abandoned or failed to prove roughly half of the allegations of the Compliance Order; those portions of the Compliance Order are vacated. EPA has, however, proved the remainder of the alleged violations. The Board thus finds at least one violation of the applicable PSD and nonattainment NSR standards at each of the TVA units referenced in the Compliance Order, with the exception of Widows Creek Unit 5. The Board's findings are summarized below.

- 1) With respect to whether TVA's projects were "physical changes" but nonetheless subject to the "routine maintenance, repair or replacement" exception under the NSR permitting programs:
- a) EPA Enforcement has met its burden of establishing that each of the fourteen projects constitutes a physical change under the statute and applicable regulations. After reviewing the statutory goals, legislative history and case law regarding NSR, the Board finds that the four factor test EPA Enforcement advocates for determining whether a project falls within the routine maintenance, repair, and replacement exception is reasonable and consistent with the statute, regulations, and case law. The Board rejects, as inconsistent with the statute, regulations, and case law, TVA's interpretation of the routine maintenance,

repair, and replacement exception. TVA's view of the breadth of the exception would swallow the rule that subjects existing sources to the requirement to install modern pollution controls when physical changes that increase emissions are made to these plants. (See Part III.C.1-. 2 of the Order)

- b) Applying the four factor test (nature and extent, purpose, frequency, and cost) to the projects at issue, TVA has not met its burden of establishing that these projects are within the ambit of "routine maintenance, repair and replacement" and, therefore, exempt from NSR's permitting requirements. (See Part III.C.3 of the Order and Appendix A)
- c) TVA's fair notice defense must fail because TVA has not established on the record in this case that the interpretation of the regulatory exception advocated by EPA Enforcement was not "ascertainably certain" from the regulation's text and its context. (See Part III.C.4 of the Order)
- d) TVA's assertion that EPA has changed its interpretation of the exception without proper notice and comment rulemaking is also rejected. (See id.)
- 2) With respect to whether TVA's projects result in "significant net emissions increases" under the applicable NSR permitting programs:
- a) The Board rejects TVA's argument that the NSR and NSPS programs must apply an identical emissions increase test, which looks to increases in the maximum hourly emissions rate of the source. (See Part III.D.3 of the Order)
- b) The Board rejects EPA Enforcement's argument that, in calculating whether the change results in an emissions increase, the pre-change, or "baseline," emissions in this case should be the annual average emissions in the two years immediately preceding the physical change. EPA Enforcement failed to rebut TVA's proof that another baseline period is more representative in this case. That period is the two-year period within the five year period preceding the particular change in which emissions were highest. (See Part III.D.4 of the Order)
- c) EPA Enforcement bases its allegations of NSR violations (other than SO_2 at Colbert Unit 5) upon an emissions increase test commonly referred to as the "actual-to-potential" test. That test compares the actual pre-change baseline to the maximum potential to emit of the unit if it were operated twenty-four hours a day for 365 days in a year. In the Compliance Order, however, the Region stated that actual pre-modification emissions are compared with "projected actual emissions" after the modification, in order to establish an NSR violation. Compliance Order ¶ 18. Given this clearly stated predicate in the Compliance Order, the Board finds that EPA Enforcement should not, on reconsideration, be permitted to substitute the more stringent actual-to-potential test. (See Part III.D.5.a of the Order)
- d) The Board rejects TVA's argument that post-change emissions should be based upon post-change historical operating data. Because the statute and regulations contemplate that the regulated entity must predict future events in order to determine whether a permit is required, it is appropriate to base a finding of violation (for failure to obtain the permit) upon what the entity reasonably could have predicted prior to beginning construction. (See Part III.D.5.b of the Order)
- e) Applying a projected actual emissions test and the representative baseline period, the Board concludes that EPA Enforcement has failed to show the requisite emis-

sions increases for a number of the pollutants at some of the units for which it had requested a finding of violation. However, the Compliance Order must be sustained with respect to twenty remaining violations of the PSD and/or nonattainment NSR permitting requirements. This includes violations of at least one pollutant for each of the fourteen units, except for Widows Creek Unit 5. (See Part III.D.5.c of the Order)

- 3) With respect to the emissions increase requirement as applied under the NSPS program and the Alabama SIP nonattainment NSR provisions applicable prior to 1983, EPA Enforcement has demonstrated that the physical changes to TVA's Colbert Unit 5 both required a nonattainment NSR permit with respect to SO₂ emissions and triggered the NSPS requirements. (See Part III.E of the Order)
- 4) EPA Enforcement has demonstrated that TVA was in violation of the minor NSR permit requirements of the Alabama and Tennessee SIPs (including provisions pertaining to the Memphis-Shelby County Air Pollution Control Board), as alleged in the Compliance Order. (See Part III.F of the Order)
- 5) With respect to the Compliance Order's remedies for the violations identified above, section IV.1.(h) of the Compliance Order (regarding surrender of SO₂ allowances) is vacated as premature. The requirements that TVA submit schedules for it to come into compliance with the CAA with respect to the violations we have sustained, and, more generally, the requirements set forth in sections IV.1.(a) to (g) of the Compliance Order are sustained. The requirements that TVA apply for, and obtain, NSR permits for the units and pollutants as to which EPA Enforcement established a violation are also sustained. Notwithstanding provisions in the Compliance Order which may purport otherwise, the determination of what pollution controls will be required under the permits must be made on a case-by-case basis by the applicable permitting authority. Such determinations must be consistent with the requirements in effect at the time of the permit applications. The portions of the Compliance Order requiring TVA to perform an audit of its coal-fired electrical generating units and remedy violations identified by the audit is sustained. (See Part III.G of the Order)

Before Environmental Appeals Judges Scott C. Fulton, Ronald L. McCallum, and Kathie A. Stein.

Opinion of the Board by Judge Stein:

This proceeding arises out of an administrative compliance order issued pursuant to sections 113 and 167 of the Clean Air Act ("CAA" or the "Act")¹ by John H. Hankinson, Regional Administrator for the United States Environmental Protection Agency ("U.S. EPA" or "Agency") Region IV (the "Region"), to the Tennessee Valley Authority ("TVA"). The administrative compliance order found that TVA had violated the CAA on numerous occasions when it made certain physical changes at TVA's coal-fired power plants that increased emissions of various pollutants. The Region amended the administrative compliance order sev-

¹ 42 U.S.C. §§ 7413, 7477.

eral times, including a substantial amendment and restatement dated April 10, 2000 (the "Compliance Order").

This proceeding is before the Environmental Appeals Board ("Board") by delegation from U.S. Environmental Protection Agency Administrator Carol M. Browner ("Administrator"), who requested that the Board issue the Agency's final decision on reconsideration of the Compliance Order, Because the Regional Administrator issued the Compliance Order as an Agency order, its operative provisions are stated either as findings of violations or as actions required to be taken by TVA. However, since the Administrator has directed us to reconsider the Compliance Order, we will generally characterize the Compliance Order's findings as allegations that must be proven in order to prevail on reconsideration, and the actions required by the Compliance Order as requests for relief. In addition, although the Region issued the Compliance Order, and thus it contains the Region's allegations, the Agency personnel arguing the case to the Board on behalf of the Region are from both the Region's enforcement office as well as from the Agency's Office of Enforcement and Compliance Assurance and Office of General Counsel, located in the Agency's headquarters. We will refer to such Agency personnel collectively as "EPA Enforcement."

For the reasons set forth below, we conclude that the Compliance Order must be sustained in part and vacated in part.

I. INTRODUCTION

This proceeding involves allegations by the Region that TVA violated the CAA when it made certain changes to nine of its coal-fired electric power generating plants without first obtaining preconstruction permits from either the EPA or, where applicable, the appropriate State or local agency. The CAA's permitting requirements are intended, among other things, to assure that pollution sources use appropriate controls to limit the emission of pollutants into the atmosphere. All of TVA's coal-fired power plants at issue in this proceeding were originally designed and built before the CAA was amended in 1977 to require persons who own or operate certain facilities that are sources of pollutant emissions to obtain preconstruction permits.

When Congress enacted the CAA in 1970, and subsequently when it amended the Act in 1977, Congress determined that existing pollution sources would be "grandfathered" — in other words, existing sources would not be required immediately to install the pollution controls the Act requires for new sources of air pollution. Congress, however, did not intend these sources to remain permanently exempt from the CAA's pollution control requirements. Instead, Congress provided that existing sources would become subject to the

CAA's requirements when these sources are "modified."² As explained by the Seventh Circuit, "[t]he purpose of the 'modification' rule is to ensure that pollution control measures are undertaken when they can be most effective, at the time of new or modified construction." Wisconsin Elec. Power Co. v. Reilly, 893 F.2d 901, 909 (7th Cir. 1990) (citation omitted) ("WEPCO"). By this structure of initially allowing grandfathering of existing sources but requiring those sources to comply with the CAA's pollution control requirements upon modification, Congress in effect balanced the competing concerns with regard to the inconvenience and cost of retrofitting existing plants with modern pollution controls and the harm to the nation's air quality from unabated air pollution.

Shortly after the enactment of the 1977 amendments to the CAA, the U.S. Circuit Court for the District of Columbia characterized the relationship between grandfathering and modification as follows:

Implementation of the statute's definition of "modification" will undoubtedly prove inconvenient and costly to affected industries; but the clear language of the statute unavoidably imposes these costs except for de minimis increases. The statutory scheme intends to "grandfather" existing industries; but the provisions concerning modifications indicate that this is not to constitute a perpetual immunity from all standards under the PSD [prevention of significant deterioration] program.

Alabama Power Co. v. Costle, 636 F.2d 323, 400 (D.C. Cir. 1980) ("Alabama Power").³ The Region's allegations that TVA violated the CAA when it made changes to nine of its coal-fired electric power generating plants without obtaining preconstruction permits requires us to decide whether those changes were "modifications" for which TVA was required to obtain preconstruction permits or, alternatively, whether the particular generating units remain "grandfathered" and thus exempt from these requirements. The answer to this question has great significance for the parties and the environment, for it determines whether or not TVA was required to install pollution control technology to minimize its emissions and comply with other requirements of the Act when it made changes to its plants.

The term "modification" is a key term used in the CAA to identify when a source owner or operator must comply with one or more of the preconstruction permitting programs created by the CAA. There are a wide array of preconstruction permitting programs that have been developed under the CAA's authority.

² The precise terms of the CAA are discussed below in Part III,B.

³ The "PSD program" refers to one of the preconstruction permitting programs created by the CAA. The PSD program is implicated in this case and will be explained more fully below.

The precise permitting requirements applicable to a particular project vary depending upon several factors, including which program applies, the air quality at the source's location, whether the permitting program is identical to the federal program or contains different provisions incorporated from state or local law, and the year in which any alleged changes were made. TVA's coal-fired electric power generating plants at issue in this case are located in the states of Alabama, Kentucky and Tennessee, and within the jurisdiction of one local permitting agency, Memphis/Shelby County, Tennessee. TVA made the alleged changes at its plants at different times between 1982 and 1996. A detailed discussion of the technical aspects of the requirements applicable to each of TVA's coal-fired units, and the changes made to those units, is provided below in Part III of this decision. Here, we provide a brief summary by way of introduction.

The rules that apply are those of EPA in effect at the applicable time, unless the State had obtained approval from EPA of its preconstruction permitting program prior to the particular change at issue, in which case the applicable rules are those of the State or local agency. Approved state programs are known as "state implementation plans" or "SIPs." The permitting requirements of the federal programs, as well as the permitting requirements of the Alabama, Kentucky, and Tennessee SIPs, are at issue in this case.

The types of required preconstruction permits generally fall into two categories, known as prevention of significant deterioration ("PSD") permits applicable in areas with air quality that is unclassifiable or is better than the national ambient air quality standards ("NAAQS"), and nonattainment new source review ("nonattainment NSR") permits applicable in areas with air quality that fails to meet the NAAQS. In the states involved in this case, a third type of permit may be required, known as a "minor" NSR permit, which applies in both attainment and nonattainment areas.

Although the specific requirements of the various NSR preconstruction permitting programs differ,⁴ a number of general features are common to all programs. The determination under the various regulatory programs of whether the source owner or operator must obtain a permit before making a change to the source is derived from the statutory definition of the term "modification." Generally, the statutory standard requires consideration of two issues: (1) whether there was a "physical change" made to the unit; and (2) whether there was an increase in the emissions of particular pollutants that results from the physical change. The regulations for the various state and federal permitting programs interpret and elaborate upon the statutory definition of "modification" by both excluding certain types of changes from the permitting requirements and by establishing requirements for determining when the change results in an emissions increase. Of par-

⁴ New source review covers both new and modified sources, as discussed below.

ticular significance for this case, the regulations typically exclude "routine maintenance, repair, and replacement" from the permitting requirements.

As explained below, the Region alleges in the Compliance Order that TVA made "physical changes" to coal-fired generating units located at nine of its plants and that those physical changes resulted in emissions increases sufficient to trigger the applicable permitting requirements. The Compliance Order also alleges that none of the physical changes at issue fall within the exception for routine maintenance, repair, and replacement. TVA raises a variety of objections to the Compliance Order, including that the particular changes at issue fall within the exception for routine maintenance, repair, and replacement and that EPA Enforcement has failed to show that the changes resulted in emissions increases sufficient to trigger the permitting requirements. In evaluating the parties' arguments and in applying the technical requirements of the regulations to the facts of this case, we shall frequently refer to the observations of the U.S. Circuit Court for the District of Columbia in *Alabama Power* and the Seventh Circuit in *WEPCO* as noted above.

This decision will address the issues raised by the parties in the following order. We will begin by providing background information regarding projects that are at issue in this case (Part II.A). We will also briefly summarize the procedural history of this reconsideration proceeding (Part II.B). In order to provide context for our legal discussion in Part III, we begin our discussion with a brief summary of our decision (Part III.A). As will be discussed, this reconsideration process has provided TVA with an opportunity to be heard regarding the factual and legal bases for the Compliance Order. In the course of this process EPA Enforcement has abandoned a number of the allegations in the Compliance Order. In addition, we also determine, as discussed below, that EPA Enforcement has not proven a number of other alleged violations on the record of this case. In these respects, the Compliance Order must be vacated in part. In other respects, we find that EPA Enforcement has proven the alleged violations by a preponderance of the evidence and that the Compliance Order must be sustained.

In our substantive discussion of the legal issues that follows the summary of our decision, we will begin by providing a more detailed discussion of the relevant provisions of the CAA, with particular emphasis on the provisions authorizing state SIPs and the requirements for PSD and nonattainment NSR permitting programs, as well as the statutory definition of "modification" (Part III.B). Second, we will discuss the "physical change" requirement and TVA's arguments that the changes it made were within the scope of the "routine maintenance, repair, and replacement" exception (Part III.C). Third, we will discuss the applicable regulatory requirements for determining whether a particular physical change has resulted in an increase in emissions of a particular pollutant (Part III.D).

Next, we will turn to the parties' arguments regarding whether the changes TVA made to one of the units, Colbert Unit 5, subject that unit to the requirements of the new source performance standard ("NSPS") program, a related pollution control program, and whether TVA operated Colbert Unit 5 in violation of the NSPS standard (Part III.E). Then we will consider whether TVA violated the "minor" NSR permitting requirements of the Alabama and Tennessee SIPs (Part III.F). Finally, we will consider the parties' arguments regarding whether the relief required by the Compliance Order exceeds the Agency's authority under the CAA (Part III.G).

II. BACKGROUND

A. TVA's Projects

TVA is an agency of the United States Federal Government that was created by the Tennessee Valley Authority Act of 1933, as amended. 16 U.S.C. §§ 831-831dd. One of TVA's responsibilities is the generation, transmission, and sale of electrical power. TVA owns and operates a system that supplies power to approximately eight million people in an 80,000 square-mile area comprising portions of seven states.

TVA owns and operates eleven coal-fired electric power generating plants, many of which contain more than one generating unit. Most of TVA's power plants were built between the early 1950s and the early 1970s. Fourteen projects at nine of TVA's coal-fired power plants are at issue in this case. The particular power plants that are at issue, the date of their original construction, the generating units (identified by unit number) at such plants, and the dates of the alleged modification are as follows:

- Allen Plant Unit 3. This unit is a 330-Megawatts ("MW") coal-fired steam boiler located in Shelby County, Tennessee, which commenced commercial operation in 1959. Construction of the alleged physical changes at Unit 3 that are at issue in this proceeding was commenced in late 1992 and completed in early 1993.
- Paradise Units 1, 2, and 3. Each of the Units 1 and 2 is a 770-MW coalfired steam boiler located in Drakesboro, Kentucky, which began commercial operation in 1963. Construction of the alleged physical changes at Unit 1 that are at issue in this proceeding was commenced and completed in

⁵ Although the Region originally alleged that the changes to TVA's Kentucky plants violated the Kentucky minor NSR permitting requirements, EPA Enforcement has abandoned those claims in its post-hearing briefs. *See infra* Part III.A.

- 1985. Construction of the physical changes at Unit 2 that are at issue in this proceeding was commenced in late 1985 and completed in early 1986. Paradise Unit 3 is a 1150-MW coal-fired steam boiler also located in Drakesboro, Kentucky. It began commercial operation in 1970. Construction of the alleged physical changes at Unit 3 that are at issue in this proceeding was commenced in late 1983 and completed in early 1985.
- Bull Run Unit 1. This unit is a 900-MW coal-fired steam boiler located near Clinton, Anderson County, Tennessee, which commenced commercial operation in 1967. Construction of the alleged physical changes that are at issue in this case was commenced and completed in 1988.
- Colbert Unit 5. This unit is a 500-MW coal-fired steam boiler located in Tuscumbia, Alabama. It began commercial operation in 1965. Construction of the alleged physical changes at Unit 5 that are at issue in this proceeding was commenced in February 1982 and completed in March 1983.
- Cumberland Unit 1 and Unit 2. Each unit is a 1300-MW coal-fired steam boiler located near Cumberland City, Tennessee, which commenced commercial operation in 1973. Construction of the alleged physical changes at Unit 1 that are at issue in this proceeding was commenced and completed in 1996. Construction of the alleged physical changes at Unit 2 that are at issue in this proceeding was commenced and completed in 1994.
- John Sevier Unit 3. This unit is a 135-MW coal-fired steam boiler located near Rogersville, Hawkins County, Tennessee. It began commercial operation in 1956. Construction on the alleged physical changes that are at issue in this proceeding was commenced and completed in 1986.
- Kingston Unit 6 and Unit 8. Each unit is a 200-MW coal-fired steam boiler located near Kingston, Roane County, Tennessee. Both units began commercial operation in 1955. Construction of the alleged physical changes at Unit 6 that are at issue in this proceeding was commenced and completed in 1989. Construction of the alleged physical changes at Unit 8 that are at issue in this proceeding was commenced in late 1989 and completed in early 1990.
- Shawnee Unit 1 and Unit 4. Each unit is a 175-MW coal-fired steam boiler located in McCracken County, Kentucky, which began commercial operation in 1953. Construction of the alleged physical changes at Unit 1 that are at issue in this proceeding was commenced in 1989 and completed in 1990. Construction of the alleged physical changes at Unit 4 that are at issue in this proceeding was commenced and completed in 1990.

• Widows Creek Unit 5. This unit is a 141-MW coal-fired steam boiler located in Jackson County, Alabama, which began commercial operation in 1954. Construction of the alleged physical changes at issue in this proceeding was commenced in late 1989 and completed in early 1990.

B. Procedural Background

1. The Issuance of the Compliance Order and Initial Consultation Between the Region and TVA

The Region originally issued the Compliance Order on November 3, 1999.⁶ The Region amended the Compliance Order several times, with a substantial amendment and restatement on April 10, 2000. The amendments to the Compliance Order made in April 2000 added more detailed findings, but did not change the central conclusion that TVA violated the CAA with respect to physical changes made to nine of its coal-fired electric power plants.

In particular, the Compliance Order, as amended, found that TVA violated the CAA when it made certain physical changes to fourteen of the boiler units at nine of its power plants without having first obtained permits under the CAA authorizing TVA to commence construction or modification of the plants. The Compliance Order found that TVA thus violated the CAA's PSD, nonattainment NSR, and NSPS requirements.

The Compliance Order also directed TVA to undertake certain actions to come into compliance with the CAA. In particular, the Compliance Order required TVA to undertake the following specific actions: (1) provide a detailed schedule for achieving compliance with all PSD and nonattainment NSR requirements; (2) provide a schedule for achieving compliance with the NSPS for those units found to be in violation of those requirements; (3) enter into a Federal Facilities Compliance Agreement; (4) submit to the appropriate federal, state, and local agencies, permit applications under the applicable NSR programs for those modifications made in violation of the CAA; (5) conduct an audit of each of its coalfired plants identifying other physical changes made to those plants for which TVA was required to have permits but which were made without such permits; (6) provide a schedule for achieving compliance with respect to any additional violations identified in TVA's audit of its coal-fired plants; and (7) for any reductions in sulfur dioxide that result from pollution control equipment added pursuant

⁶ Prior to the issuance of the original Compliance Order, EPA Enforcement sent TVA a letter dated July 9, 1999, alleging that TVA had violated the CAA when it performed various replacement projects at its plants without the appropriate NSR permits. In this letter, EPA Enforcement requested a meeting with representatives of TVA to discuss these allegations. *See* TVA Response to Initial Brief, Ex. V.

to the Compliance Order, retire sulfur dioxide allowances equivalent to such reductions and be prohibited from using such reductions or selling them to any other utility.

After the Compliance Order was originally issued in November 1999, TVA requested a conference with Regional Administrator Hankinson, and a meeting was held on December 20, 1999. At that meeting, TVA submitted a brief (the "December 1999 Brief") describing its objections to the Compliance Order and requested that the Agency withdraw and reconsider the Compliance Order. Briefly, TVA argued that its projects were not "modifications" of the respective units on the ground that the particular physical changes were "routine maintenance, repair, and replacement" within the meaning of the applicable regulations, and it provided an extensive discussion of various statements attributed to EPA regarding the meaning of the phrase "routine maintenance, repair, and replacement." December 1999 Brief at 7-22. In its December 1999 Brief, TVA also argued that none of the physical changes made to its coal-fired plants resulted in a "significant net emissions increase." *Id.* at 23-31. Finally, TVA argued that the actions required of it by the original version of the Compliance Order are not authorized by the CAA. *Id.* at 32-35.

2. Administrator's Delegation to the Board

On May 4, 2000, the Administrator issued a memorandum to the Board ("Administrator's Memorandum") directing that the Board conduct appropriate proceedings upon reconsideration of the Compliance Order, assuming that Regional Administrator Hankinson decided that the Compliance Order should be reconsidered. The Administrator also requested that the Board issue a final decision on behalf of the Agency by September 15, 2000. The Administrator's Memorandum requested that EPA Enforcement and TVA be provided an opportunity to conduct limited discovery and provide limited oral testimony, and that the administrative record be closed by August 1, 2000.

3. Prehearing Orders by the Board

By order dated May 15, 2000, the Board referred the prehearing and evidentiary hearing proceedings in this case to the Agency's Office of Administrative Law Judges. The Board's May 15 Order requested that the Administrative Law Judge assigned to the case present to the Board a complete record of the prehearing and evidentiary hearing proceedings by August 1, 2000. The May 15 Order also stated that, in conducting the prehearing and evidentiary hearing proceedings, the Administrative Law Judge was to look for guidance to the Consolidated Rules

 $^{^{7}}$ Regional Administrator Hankinson subsequently granted reconsideration by letter dated May 4, 2000.

of Practice set forth at 40 C.F.R. part 22.8 Thereafter the Chief Administrative Law Judge appointed Administrative Law Judge Andrew S. Pearlstein to preside over the prehearing and evidentiary hearing proceedings in this case.

The Board's May 15 Order also stated that the Board retained jurisdiction of this matter to conduct additional proceedings concurrently with the prehearing and evidentiary hearing proceedings discussed above. In particular, to facilitate the timely resolution of this matter, the Board directed that TVA and EPA Enforcement file briefs on certain issues, including briefs regarding the allocation of the burden of proof on the various claims and defenses asserted by the parties and briefs discussing the circumstances under which the law requires the owner or operator of a source to obtain (a) a PSD permit pursuant to 40 C.F.R. § 52.21, or pursuant to the applicable SIP, (b) a nonattainment NSR permit, and (c) a "minor NSR permit." The Board's Order also required EPA Enforcement to respond to various arguments made by TVA in its December 1999 Brief. After receiving briefs from the parties regarding allocation of the burdens of production and persuasion on the claims and defenses raised by the parties, in order to provide guidance to the parties during the evidentiary hearing, the Board issued an order dated July 3, 2000, regarding the allocation of such burdens.

On May 17, 2000, TVA filed a motion seeking rescission of the Board's May 15 Order. In essence, TVA argued that the schedule set forth collectively in the Administrator's Memorandum, the May 15 Order and an order issued by Judge Pearlstein on May 17 did not provide TVA a full and fair opportunity to understand the allegations on which EPA Enforcement intended to focus in this proceeding and the basis for these allegations, and to test the rationale of EPA's allegations. EPA Enforcement opposed the motion. The Board denied that motion by order dated June 2, 2000, holding, *inter alia* that this proceeding is not a formal part 22 proceeding, that TVA is not entitled to discovery, and that the schedule in this proceeding has granted TVA significantly greater discovery and hearing rights than required by CAA § 113(a), 42 U.S.C. § 7413(a). By motion dated July 3, 2000, TVA renewed its motion to rescind on the grounds that events subsequent to June 2, 2000, demonstrated that this proceeding is "unfair" to TVA. After receiving a response from EPA Enforcement, the Board denied TVA's renewed motion to rescind by order dated July 7, 2000.9

⁸ The Board's May 15 Order also stated that the Administrative Law Judge was not being requested as part of this referral to make, or recommend, findings of fact or conclusions of law at the conclusion of the hearing in this matter; rather, we stated that the Board would make findings as necessary and appropriate upon receipt from the Administrative Law Judge of the record of the proceeding.

⁹ In our view, the material issues were developed sufficiently to allow for an informed decision on our part, and we do not believe that TVA has been prejudiced during this reconsideration process by the pace of the proceedings.

4. Judge Pearlstein's Prehearing Orders

On May 17, 2000, Judge Pearlstein entered an initial order governing the conduct of the prehearing and evidentiary hearing proceedings. Judge Pearlstein's May 17 Order, among other things, allowed the parties to begin discovery immediately "on a voluntary, cooperative basis * * * to the maximum extent possible," and it established a schedule for the parties to provide a prehearing information exchange of the type contemplated by 40 C.F.R. § 22.19. Judge Pearlstein's May 17 Order also scheduled a prehearing conference in early June 2000 and tentatively scheduled the evidentiary hearing on eight days in mid-July 2000. 10

At the prehearing conference, which was held on June 7, 2000, in Knoxville, Tennessee, the parties agreed to a revised schedule for prehearing exchanges, a schedule for the parties to submit discovery disputes to Judge Pearlstein for resolution, and a schedule for the evidentiary hearing, providing for it to begin on July 11, 2000. Summary of Prehearing Conference (ALJ, June 9, 2000). Judge Pearlstein also stated, consistent with the Board's orders, that generally there is no right per se to discovery in Agency administrative proceedings and that any discovery disputes would be determined by the standards set forth in 40 C.F.R. § 22.19(e). *Id.* at 1.

During June, the parties submitted various discovery disputes to Judge Pearlstein concerning their requests for production of documents and interrogatories propounded to each other. On June 29, 2000, Judge Pearlstein issued an order, titled "Rulings and Guidelines on Discovery," in which he discussed the discovery disputes raised by the parties as of that date. In that order, Judge Pearlstein noted as follows:

¹⁰ In addition, Judge Pearlstein's May 17 Order directed TVA to file an "answer" to the allegations of the Compliance Order, thereby treating the Compliance Order as functionally equivalent to a complaint for the purposes of framing the issues for the evidentiary hearing. In its answer to the Compliance Order, dated May 26, 2000, TVA asserted several affirmative defenses, including statute of limitations (TVA's Answer to EPA's Fourth Amended Order and Request for Information ("TVA Answer") ¶ 106), and failure on EPA Enforcement's part to issue an "adequate and reasonably intelligible Notice of Violation 30 days in advance of bringing this proceeding as required by 42 U.S.C. § 7413." TVA Answer ¶ 113. TVA did not reassert these two defenses in its post-hearing briefs and, for those reasons TVA appears to have abandoned them. In any event, neither defense is meritorious, By its terms, the statute of limitations at 28 U.S.C. § 2462 applies only to actions for fines and penalties. In this case, where the government is only seeking equitable or injunctive relief and not a penalty within the meaning of § 2462, the claims are not time limited. See United States v. Telluride Co., 146 F.3d 1241, 1248 (10th Cir. 1998); United States v. Banks, 115 F.3d 916, 919 (11th Cir. 1997), cert. denied, 522 U.S. 1075 (1998), reh'g denied, 523 U.S. 1041 (1998). Moreover, we have reviewed the notice of violation issued by EPA Enforcement to TVA on or about March 9, 2000, and are unpersuaded that it fails to comply with the statutory notice requirement set forth in CAA § 113(a), 42 U.S.C. § 7413(a).

[A]s the parties are aware, the vast bulk of discovery in this case must be accomplished on a voluntary basis. The river of discovery is flowing and can only be slightly nudged to one side of the channel or the other by these rulings or guidelines.

Rulings and Guidelines on Discovery at 2. Judge Pearlstein also stated that "[i]t must also be remembered that this is a proceeding to reconsider an administrative compliance order. * * * This is not a federal court action or even a standard Part 22 administrative enforcement proceeding." *Id.* at 3. Judge Pearlstein observed that the parties would not have time in this proceeding to produce and review large volumes of documents and that "[t]he parties' resources would best be devoted to preparing their own cases and analyzing the actual evidence proposed by the opposing party as revealed in the prehearing exchange." *Id.* at 3-4.

In turning to the parties' arguments, Judge Pearlstein largely sustained EPA Enforcement's objections that TVA's document requests were "vague and likely to include an unreasonably large number of documents of little or no probative value." *Id.* at 4. Judge Pearlstein also held that "TVA has not shown generally that many of the categories of documents it is seeking will have significant probative value on a disputed issue of material fact in this proceeding." *Id.*

5. The Evidentiary Hearing

Judge Pearlstein began the evidentiary hearing on the morning of July 11, 2000, and completed the hearing in the evening of July 17, 2000. At the request of the Board, the evidentiary hearing was recorded on video tape as well as by transcript.¹² At the evidentiary hearing, EPA Enforcement called four witnesses and

Given the volume of relevant evidence in the record pertaining to each of the issues, we do not disagree with Judge Pearlstein's conclusions in this regard.

¹² On September 14, 2000, as the Board was completing this order, TVA filed an "Errata Sheet" regarding the transcript of the hearing in this matter (July 11 to 17, 2000). The Errata Sheet consists of twenty-four pages of changes that TVA apparently would like to have made to the transcript, accompanied by largely handwritten changes to the 1,105 page transcript. TVA, however, did not file a motion seeking approval of the suggested changes. We have previously stated that the Agency's Consolidated Rules of Practice, 40 C.F.R. Part 22, should be considered as guidance in the evidentiary hearing phases of this proceeding. May 15 Order at 2. Those rules provide that "[a]ny party may file a motion to conform the transcript to the actual testimony within 30 days after receipt of the transcript, or 45 days after the parties are notified of the availability of the transcript, whichever is sooner." 40 C.F.R. § 22.25. Under the guidance of this rule, we conclude that TVA's Errata Sheet must be rejected. TVA has made no showing that its submission is timely under the rule. (Moreover, we find that it is unreasonable for TVA to file its proposed Errata Sheet one day prior to the date on which a final decision was expected in this matter.) TVA also failed to file a motion seeking to conform the transcript to the "actual testimony." After reviewing relevant portions of the videotape, we find that several of TVA's suggested changes do not seek to conform the transcript to the actual testi-Continued

introduced more than 300 exhibits. Briefly, EPA Enforcement called the following four witnesses who testified regarding the following subjects:

- 1. Joseph Van Gieson, who provided a general description of the boilers of coal-fired electrical power plants and air emissions analysis. Mr. Van Gieson also provided testimony regarding the operation and mechanics of coal-fired electric generating units and emissions estimation techniques and calculation of emissions from coal-fired power plants. Mr. Van Gieson prepared written testimony, which was submitted prior to the hearing and admitted into evidence at the hearing as EPA Enforcement Ex. 277.
- 2. Donald Randolph, who testified regarding his experience in various roles as a former employee and manager in TVA's maintenance department, including his experience with boiler maintenance projects at TVA. Mr. Randolph provided detailed testimony regarding the project at Widows Creek Unit 5. Mr. Randolph, who was subpoenaed to appear by EPA Enforcement, did not submit written testimony.
- 3. Michael J. Majoros, Jr., who testified regarding accounting rules applicable to public utility companies and classification of their assets and expenses. Mr. Majoros prepared written testimony, which was submitted prior to the hearing and admitted into evidence at the hearing as EPA Enforcement Ex. 280. In general, Mr. Majoros testified regarding the accounting records of the costs associated with the particular generating units at issue in this case and the accounting of the expenses associated with the fourteen physical changes at those units.
- 4. Alan Michael Hekking, who testified regarding maintenance of coal-fired electric power plants. Based on his experience as a former TVA plant manager, Mr. Hekking prepared written testimony, which was submitted prior to the hearing and admitted into evidence at the hearing as EPA Enforcement Ex. 279. Mr. Hekking also provided more detailed testimony regarding the reheater replacement project at Allen Unit 3.

At the evidentiary hearing, TVA called five witnesses and introduced thirteen exhibits including attachments. Briefly, TVA called the following witnesses who testified regarding the following subjects:

1. Jerry Golden, who testified about TVA's practices with respect to maintenance, repair, and replacement. Mr. Golden prepared written testimony, which

⁽continued)

mony, but, remarkably, instead seek to add words or phrases that clearly were not spoken by the witnesses. *See, e.g.*, suggested changes to Tr. at 735, 766. Although, based on our preliminary review of TVA's proposed changes for purposes of determining whether to accept the substitutions, we have found nothing that would affect our decision, for the foregoing reasons, we reject this submission.

was submitted prior to the hearing and admitted into evidence at hearing as TVA Ex. 4.

- 2. James Callahan, who testified on the accounting rules regarding the capitalization of plant-related expenditures and their implications under the CAA. Mr. Callahan prepared written testimony, which was submitted prior to the hearing and admitted into evidence at the hearing as TVA Ex. 6.
- 3. Gordon George Park, who testified regarding TVA's environmental compliance practices. Mr. Park prepared written testimony, which was submitted prior to the hearing and admitted into evidence at the hearing as TVA Ex. 5.
- 4. Donald Price Houston, who testified regarding the data and calculations of emissions at the nine units at issue. Mr. Houston prepared written testimony, which was submitted prior to the hearing and admitted into evidence at the hearing as TVA Ex. 9.
- 5. Joseph R. Bynum, who testified regarding TVA's power system, including load demand, TVA's overall maintenance philosophy, TVA's Fossil and Hydro Unit Evaluation and Modernization Program ("FHUEM") report and the implications to TVA if EPA's regulatory interpretation should apply. Mr. Bynum prepared written testimony, which was submitted prior to the hearing and admitted into evidence at the hearing as TVA Ex. 12.

On July 17, 2000, Judge Pearlstein concluded the hearing and sent the complete record to the Board for its decision on reconsideration.

6. Filings Before the Board

Pursuant to the Board's May 15 Order, the parties entered into and filed a comprehensive stipulation as to the air quality designation (as either attainment or nonattainment of the NAAQS) in the areas of TVA's plants at the time of the various projects. *See* Joint Stipulations of Applicable Regulations and Attainment Status (August 2, 2000) ("Regulation Stipulation"). In the Regulation Stipulation, the parties also stipulated to the SIP provisions and federal regulations applicable during the relevant time periods. The parties attached copies of the SIP and federal regulation texts to the Regulation Stipulation in numbered tabs from 1 to 23. *Id.* Throughout this decision, we will generally refer to the Regulation Stipulation and the numbered tabs as citations for the relevant regulatory text.

Currently, the Board has before it EPA Enforcement's, TVA's, and non-parties Southern Alliance for Clean Energy and Natural Resource Defense Coun-

cil's ("SACE/NRDC")¹³ briefs on the merits of the Compliance Order, which total more than 600 pages in length. These briefs include: the Initial Brief of EPA Enforcement filed June 15, 2000 ("EPA Initial Brief"); Brief of the Tennessee Valley Authority in Response to the Initial Brief of EPA Enforcement, filed July 5, 2000 ("TVA Response to Initial Brief"); Post-Hearing Brief for SACE/NRDC, filed August 4, 2000; EPA Enforcement's Post-Trial Memorandum, filed August 4, 2000 ("EPA Enforcement Post-Hearing Brief"); Initial Post-Hearing Brief of the Tennessee Valley Authority, filed August 4, 2000 ("TVA Post-Hearing Brief"); EPA Enforcement's Post-Hearing Reply Brief, filed August 11, 2000 ("EPA Enforcement Reply Brief") and the Response Post-Hearing Brief of the Tennessee Valley Authority, filed August 11, 2000 ("TVA Reply Brief"). On July 31, 2000, Babcock and Wilcox Company, which is not a party in this matter, also filed a document entitled "Amicus Curiae Filing of the Babcock and Wilcox Company" without leave from the Board to do so.¹⁴

Additionally, TVA has filed with the Board two motions¹⁵ to compel further discovery. *See* Motion of Tennessee Valley Authority to Compel Discovery, filed July 11, 2000 ("TVA's Motion to Compel Discovery"); Second Motion of the Tennessee Valley Authority to Compel Discovery, filed July 31, 2000 ("TVA's Second Motion to Compel Discovery"); and the Reply Memorandum in Support of Motion of Tennessee Valley Authority to Compel Discovery, filed July 31, 2000 ("TVA's Reply Memo Supporting Motion to Compel Discovery").

In these motions, TVA requests the Board to compel EPA Enforcement to "comply with the Discovery Order and to produce certain relevant documents." See, e.g., TVA's Second Motion to Compel Discovery at 1. Further, in TVA's second motion to compel, TVA requests the Board to compel EPA Enforcement to produce additional documents because the documents EPA Enforcement produced through discovery revealed additional documents not produced and because EPA Enforcement raised additional claims at the hearing that were not included in the Compliance Order. See id. at 1. EPA Enforcement has responded to TVA's

¹³ The Board granted SACE/NRDC the opportunity to submit non-party briefs, essentially as an amicus, under the rules generally applicable to Agency administrative enforcement proceedings. *See* Order Denying Motion to Intervene, Granting Leave to File Non-Party Briefs, and Scheduling Post-Hearing Briefing (EAB, June 16, 2000).

¹⁴ EPA Enforcement objects to the Babcock & Wilcox filing on the grounds that it was not properly filed and that it contains mostly factual assertions that should have been submitted into evidence at the hearing in order to allow an opportunity for cross examination. We find that Babcock & Wilcox filed this document without leave of the Board and failed to properly serve the parties. Additionally, the facts asserted in the document were facts that should have been introduced as evidence at hearing. *See* Order Denying TVA Motion to Rescind Scheduling Orders at 14 (EAB, June 2, 2000). Accordingly, we strike this filing from the record and will not consider it further.

¹⁵ The first motion was submitted during the hearing, and Judge Pearlstein requested that the Board rule on it. The second motion was submitted after the close of the hearing.

discovery motions. See EPA Enforcement's Response in Opposition to Tennessee Valley Authority's Motion to Compel Discovery, filed July 17, 2000 ("EPA Enforcement Response to Motion to Compel"); and EPA Enforcement's Response in Opposition to Tennessee Valley Authority's Second Motion to Compel Discovery and TVA's Reply Memorandum in Support of Its Motion to Compel Discovery, filed August 17, 2000 ("EPA Enforcement's Response to TVA's Second Motion to Compel Discovery"). Because we do not see the additional discovery sought by TVA as ultimately leading to the addition of evidence adding significant probative value to the substantial information already in the record relating to these issues, we deny both of TVA's motions to compel discovery. 16

EPA Enforcement has also filed a motion with the Board to compel the return of documents which EPA Enforcement alleges are privileged. *See* Motion to Compel the Return of Privileged Documents Inadvertently Produced (July 25, 2000) ("EPA Enforcement's Motion to Compel Return of Privileged Documents"); *see also* Reply Supporting Its Motion to Compel the Return of Privileged Documents"

The Board finds that EPA Enforcement has produced a large portion of the documents requested in TVA's motions to compel. In particular, EPA Enforcement has produced NSR determinations, including but not limited to those in the Agency's publically available "NSR Prevention of Significant Deterioration and Nonattainment Area Notebooks." With respect to those documents TVA requested that EPA has not produced, we find that TVA's motions to compel fall short of satisfying the provisions of 40 C.F.R. § 22.19(e), seek information that is largely cumulative of other information in the record, and reassert discovery disputes largely resolved by Judge Pearlstein in his Rulings and Guidelines on Discovery.

Specifically, TVA's motions do not address with enough specificity the requirement that such a motion for further discovery be granted only if it "seeks information that has significant probative value on the disputed issue of material fact relevant to liability or relief sought." See 40 C.F.R. § 22.19(e). TVA fails to identify the significant probative value of the documents requested, and, as Judge Pearlstein wrote in the order, we are unwilling to presume to which issues the documents relate. See Rulings and Guidelines on Discovery at 4.

Furthermore, the documents that TVA seeks are, for the most part, cumulative of the already extensive evidence in the record. As Judge Pearlstein observed, considerable discovery has taken place on a voluntary basis. In fact, EPA Enforcement states that it has produced approximately 135,000 pages to TVA. See EPA Enforcement's Motion to Compel Return of Privileged Documents (July 25, 2000). TVA has not shown how the documents sought are not otherwise cumulative.

Finally, TVA's motions also seek documents that go beyond Judge Pearlstein's Rulings and Guidelines on Discovery (e.g., state documents from states where no TVA plants are located). We accord significant deference to an Administrative Law Judge's discovery rulings, *In re Chempace Corp.*, 9 E.A.D. 119 (EAB 2000), and are unpersuaded by TVA's arguments for additional discovery.

The Board denies both motions to compel further discovery for the following reasons. Initially, we note that the Compliance Order was issued pursuant to sections 113(a) and 167 of the CAA, 42 U.S.C. §§ 7413(a), 7477, which do not provide for any discovery. *See* Order Denying TVA Motion to Rescind Scheduling Orders (June 2, 2000). To the extent discovery has been allowed in this proceeding, we have used the standards set forth in 40 C.F.R. § 22.19(e) to guide the discovery process. *Id.* at 13.

ments Inadvertently Produced (Aug. 18, 2000) ("EPA Enforcement's Response to Motion to Compel Return of Privileged Documents"). TVA has responded to this motion by filing two briefs in opposition: Opposition of Tennessee Valley Authority to EPA Enforcement's Motion to Compel the Return of Privileged Documents Inadvertently Produced (July 31, 2000) ("TVA's Response to EPA Enforcement's Motion to Compel Return of Privileged Documents"), and Reply of Tennessee Valley Authority to EPA Enforcement's Motion to Compel the Return of Privileged Documents Inadvertently Produced (Aug. 31, 2000) ("TVA's Reply to EPA Enforcement's Motion to Compel Return of Privileged Documents"). 17

17 EPA Enforcement requests that TVA be compelled to return six documents that allegedly were "inadvertently released" by EPA Enforcement to TVA during the course of discovery. Each of those six documents is an internal EPA memorandum related to inspections, enforcement reviews or other regulatory action with respect to power plants owned by Tampa Electric Company. As authority for its request, EPA Enforcement cites allegedly applicable case law regarding when a party waives its privilege as well as the "Protective Order," which was signed by both EPA Enforcement and TVA and then issued by Judge Pearlstein on July 6, 2000. In a subsequent pleading, EPA Enforcement states that four of the documents were not inadvertently released, but instead were "mistakenly" released. Reply Supporting Motion to Compel Return of Privileged Documents, at 4 n.4. In opposing EPA Enforcement's request, TVA argues that the Protective Order does not apply to EPA Enforcement's privilege claims and that, under applicable law, EPA Enforcement has waived any privilege.

Upon review we conclude that the Protective Order does govern whether the documents identified by EPA Enforcement are to be treated as confidential. The Protective Order applies to "Confidential Information," which is defined as documents or other information marked as confidential and which "a Party believes in good faith * * * is entitled to confidential treatment pursuant to 40 C.F.R. Part 2." Protective Order ¶ 2. Included among the types of information entitled to confidential treatment under Part 2 are "[i]nter-agency or intra-agency memorandums or letters which would not be available by law to a party other than an agency in litigation with an agency." 40 C.F.R. § 2.118(a)(5). Even if information has not been marked as confidential in the manner required by the Protective Order and has been inadvertently disclosed, such information may nonetheless be treated as Confidential Information pursuant to the procedures governing inadvertent disclosure identified in paragraph 10 of the Protective Order.

Applying these standards here, we conclude that five of the documents identified by EPA Enforcement in its Motion are not entitled to protection as Confidential Information under the terms of the Protective Order. Paragraph 10 only applies to "inadvertent or unintentional disclosure." EPA Enforcement has admitted that "[f]our of the six documents were intentionally released to TVA." Intentional release is, in our view, the opposite of inadvertent, and is the essence of a knowing waiver. EPA Enforcement has only identified the four intentionally released documents as "enforcement inspection reports at Tampa Electric Company ('TECO') facilities." Reply Supporting Motion to Compel Return of Privileged Documents at 4 n.4. Absent a better description of the four intentionally released documents, we rely upon TVA's statement that five of the six documents were found by TVA in a file titled "Region 4 TECO Inspection Reports." TVA's Opposition to Privilege Document Motion at 13. These five documents shall be treated as intentionally released and not entitled to treatment as Confidential Information under the Protective Order. As to the last document, bates range EPAOEC 049391 — 049406, EPA Enforcement has demonstrated that it was inadvertently disclosed and that it is the type of internal Agency memorandum entitled to confidential treatment under 40 C.F.R. Part 2. Therefore, this document is entitled to treatment as Confidential Information under the terms of the Protective Order and must not be disclosed by TVA, or its attorneys, to any third party.

Finally, through EPA Enforcement's Post-Hearing Reply Brief, EPA Enforcement objected to several documents that TVA had attached to its post-hearing brief. TVA responded to EPA Enforcement's objections in its August 17, 2000 filing, Tennessee Valley Authority's Response to EPA Enforcement's Objections Regarding the Scope of the Factual Record. For reasons stated in note 18, we deny EPA Enforcement's request to exclude those documents.

III. DISCUSSION

As noted above, the parties have raised a variety of legal and factual issues primarily relating to whether the changes made by TVA to its plants fall within the "routine maintenance, repair, and replacement" exception and whether those changes result in an emissions increase. In this part of our decision, we will discuss the issues raised by the parties and explain our conclusions. We begin by summarizing our conclusions.

A. The Compliance Order Must Be Sustained in Part and Vacated in Part

As discussed more fully below, based on the record of this reconsideration proceeding, we find that in a number of respects the Compliance Order cannot be sustained. In particular, EPA Enforcement has, during the course of this proceeding, abandoned certain allegations made in the Compliance Order. Moreover, as discussed below, we conclude that the record does not support a number of the allegations of increased emissions. On the other hand, in several important respects, we find that the Compliance Order must be sustained.

We reject TVA's primary defense — that all of the projects were undertaken as routine maintenance, repair, and replacement — for the reasons stated in Part III.C below. In summary, we conclude that EPA Enforcement has met its burden of establishing that each of the fourteen projects constitutes a physical change under the statute and applicable regulations. After reviewing the statutory goals, legislative history, and case law regarding NSR, the Board finds, as discussed below, that the four factor test EPA Enforcement advocates for determining whether a project falls within the routine maintenance, repair, and replacement exception is reasonable and consistent with the statute, regulations, and case

¹⁸ EPA Enforcement has objected to a number of tables and attachments that were included in TVA's Post-Hearing Brief, on the grounds that TVA submitted them after the close of the record on August 1, 2000. EPA Enforcement requests that the Board exclude those documents from the record. Although the documents were submitted after August 1, 2000, we find that the majority of the documents TVA included in its Post-Hearing Brief have little probative value to the case at hand and EPA Enforcement will not be prejudiced by these late submissions. Therefore, we will not exclude those documents from the record.

law. Further, the Board rejects, as inconsistent with the statute, regulations, and case law, TVA's interpretation of the routine maintenance, repair, and replacement exception. TVA's view of the breadth of the exception would, in our view, swallow the rule that subjects existing sources to the requirement to install modern pollution controls when physical changes that increase emissions are made to these plants.

We then apply the four factor test to the projects at issue to determine whether the projects are within the scope of the exception. In doing so, we find that TVA has not met its burden of establishing that these projects are within the ambit of "routine maintenance, repair, and replacement" and therefore exempt from NSR's permitting requirements. TVA has also raised a fair notice defense and an improper rulemaking defense to EPA Enforcement's use of its interpretation of routine maintenance, repair, and replacement. We find both defenses must fail for the reasons stated in Part III.C below. TVA has not established on the record in this case that the interpretation of the regulatory exception advocated by EPA Enforcement was not "ascertainably certain" from the regulation's text and its statutory context. TVA's assertion that EPA has changed its interpretation of the exception without proper notice and comment rulemaking likewise fails.

Although we reject TVA's primary defense, we nevertheless conclude, as discussed below, that the Compliance Order can be only partially sustained and must be vacated in a number of respects because of a lack of proof, particularly proof of increases of pollutant emissions. First, the Region alleged in the Compliance Order that, as a result of the changes made by TVA to Paradise Unit 3, TVA allegedly violated the NSPS. Compliance Order ¶¶ 95-98. In its Post-Hearing Brief, EPA Enforcement states that EPA Enforcement "is withdrawing the NSPS violation for Paradise Unit 3." EPA Enforcement Post-Hearing Brief at 163 n.102. Thus, the allegations regarding Paradise Unit 3's violation of the NSPS must be vacated.

Second, with respect to Colbert Unit 5, the Region alleged that TVA failed to comply with "the [NSPS] emission standards, testing, notification, record keeping, and reporting requirements." Compliance Order ¶ 102. However, EPA Enforcement introduced no evidence as to whether the post-change emissions from Colbert Unit 5 exceeded the emissions standards of 40 C.F.R. part 60, subpart Da. Thus, the allegation that the operation of Colbert Unit 5 violated the emissions standard of the NSPS must be vacated. 19

¹⁹ However, for the reasons discussed below in Part III.E, we conclude that the Compliance Order must be sustained with respect to the allegations that at Colbert Unit 5 TVA violated the NSPS requirements for testing, record keeping, and reporting.

Third, the Compliance Order alleged that the changes made to each of the fourteen units at issue in this proceeding required a minor NSR permit from Alabama, Kentucky, Tennessee, or Memphis/Shelby County and that the failure to obtain such minor NSR permits violated the applicable state SIP. Compliance Order ¶¶ 50, 52, 60, 62, 70, 72, 74, 76, 78. In its Post-Hearing Brief, EPA Enforcement does not argue that any of the changes made to the units located in Kentucky (Paradise Units 1, 2 and 3, and Shawnee Units 1 and 4) violated the Kentucky minor NSR permitting requirements. *See* EPA Enforcement Post-Hearing Brief at 83-89. Accordingly, we conclude that EPA Enforcement has abandoned the allegations as to violation of the Kentucky minor NSR permitting requirements with respect to the changes made to these five units. Accordingly, in this respect the Compliance Order also must be vacated.²⁰

Fourth, the Compliance Order alleged that each of the changes made to the fourteen units at issue resulted in a significant net emissions increase in the emissions of nitrogen oxides (" NO_X "), sulfur dioxide (" SO_2 "), or particulate matter ("PM") requiring PSD and/or nonattainment NSR permitting. Compliance Order ¶¶ 50, 52, 60, 62, 70, 72, 74, 76, 78. In its Post-Hearing Brief, EPA Enforcement fails to argue that the changes to the following units resulted in a significant net emissions increase with respect to the following pollutants:

Allan Unit 3 — PM
Cumberland Units 1 and 2 — SO₂
John Sevier Unit 3 — PM
Kingston Unit 6 — PM
Paradise Units 1, 2 and 3 — SO₂ and PM
Shawnee Units 1 and 4 — PM

See EPA Enforcement Post-Hearing Brief at 73-90. Accordingly, we conclude that EPA Enforcement has abandoned the allegations as to violations with respect to these pollutants at the identified units. To the extent that the Compliance Order intended to allege permitting violations with respect to all three pollutants at each unit, the Compliance Order cannot be sustained.

EPA Enforcement has, however, by virtue of the proof it has proffered, not abandoned the allegations of violations with respect to the following pollutants at the identified units (an "X" indicates that a finding of violation is requested with respect to the pollutant):

²⁰ We discuss the allegations regarding violation of the Alabama, Tennessee, and Memphis/Shelby County minor NSR permitting requirements in Part III.F below and conclude that the allegations that TVA violated these requirements must be sustained.

Chart No. 1

	NO _X	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	X
Colbert Unit 5	X	X	X
Cumberland Unit 1	X		X
Cumberland Unit 2	X		X
John Sevier Unit 3	X	X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	X
Paradise Unit 1	X		
Paradise Unit 2	X		
Paradise Unit 3	X		
Shawnee Unit 1	X	X	
Shawnee Unit 4	X	X	
Widows Creek Unit 5	X	X	X

EPA Enforcement Post-Hearing Brief at 73-90. In our discussion below, we will refer to this chart, which reflects twenty-nine alleged violations, as summarizing EPA Enforcement's requests for findings of violation.

As will be discussed below in Part III.D, EPA Enforcement bases its twenty-nine remaining requests for findings of NSR violations upon an emissions increase test commonly referred to as the "actual-to-potential" test, which compares actual pre-change emissions (based on the annual average emissions in a two-year baseline period) to the maximum potential to emit of the unit if it were operated twenty-four hours a day for 365 days in a year. EPA Enforcement bases its request for findings of violation on an actual baseline period that is the two years immediately preceding the changes made to each of the units. For the reasons stated in Part III.D.4, we conclude that the preponderance of the evidence in the record here establishes that another baseline period is more representative in this case — the two-year period with the highest emissions within the five year period preceding the particular change, not the two years immediately preceding the changes. In Part III.D.5, we further note that in the Compliance Order the Region stated that actual premodification emissions are compared with "projected actual emissions" after the modification, in order to establish an NSR violation.

Compliance Order ¶ 18. Therefore, we conclude that, given this clearly stated predicate in the Compliance Order, that EPA Enforcement should not, on reconsideration, be permitted to apply the actual-to-potential test.

In Part III.D.5, we explain why we conclude that a finding of violation for failure to obtain a preconstruction permit should be based upon what the source owner reasonably could have predicted prior to beginning construction. Applying a projected actual emissions test and the more representative baseline period, we conclude for the reasons stated in Part III.D.5.c that EPA Enforcement has failed to show the requisite emissions increases for a number of the pollutants at some of the units for which it had requested a finding of violation. For Widows Creek Unit 5, we find that EPA Enforcement has failed to show the requisite increase for any of the three identified pollutants. In total, considering all pollutants and units for which EPA Enforcement either abandoned the NSR claims made in the Compliance Order or failed to sustain its proof, the record does not support the Compliance Order's allegations with respect to twenty-one alleged violations, considering each pollutant at each unit as a separate violation. Accordingly, we are vacating these portions of the Compliance Order. However, we also find, as discussed below in Part III.D.5.c (and Part III.E, where SO₂ emissions from Colbert Unit 5 are discussed), that the Compliance Order must be sustained with respect to the twenty-one remaining violations of the PSD and/or nonattainment NSR permitting requirements. This includes violations of at least one pollutant for each of the fourteen units, except for Widows Creek Unit 5.

In summary, as discussed below, we find that EPA Enforcement has demonstrated that TVA violated the PSD and nonattainment NSR permitting requirements with respect to the following pollutants at the identified units:

Chart No.2

	NO _x	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	
Colbert Unit 5	X	X	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		
John Sevier Unit 3		X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	
Paradise Unit 1	X		
Paradise Unit 2	X		
Paradise Unit 3	X		
Shawnee Unit 1	X	X	
Shawnee Unit 4	X	X	

We also find, as discussed below, that EPA Enforcement has demonstrated that TVA violated the minor NSR permitting requirements of the applicable state SIPs with respect to the following pollutants at the identified units:

Chart No.3

	NO _x	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		X
John Sevier Unit 3	X	X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	X
Colbert Unit 5	X	X	X
Widows Creek Unit 5	X	X	X

Next, we begin our analysis with a brief discussion of the statutory requirements of the Act.

B. General Requirements of the Clean Air Act and Regulations

Many of the principal issues raised by the parties in this case relate to the statutory definition of "modification," which, as we have said, defines when older pollution sources, including ones that were constructed before the CAA permitting requirements were enacted, become subject to the pollution control requirements of the NSR and NSPS programs. In this part, we will describe the general requirements of the CAA that are implicated in this case, with particular emphasis on the role of the term "modification" in those general requirements.

1. The National Ambient Air Quality Standards

The CAA is designed to protect and enhance the nation's air quality. CAA § 101(b)(1), 42 U.S.C. § 7401. The 1970 amendments to the CAA required the EPA to promulgate NAAQS to regulate the emission of certain pollutants into the atmosphere. The NAAQS are "maximum concentration 'ceilings'" for particular pollutants, "measured in terms of the total concentration of a pollutant in the atmosphere." *In re Haw. Elec. Light Co.*, 8 E.A.D. 66, 72 (EAB 1998). As noted above, the air quality of a particular area is expressed in terms of whether the area is classified as "attainment," "unclassifiable," or "nonattainment" of the NAAQS for a particular pollutant. NAAQS have been set for six criteria pollutants: sulfur

oxides,²¹ particulate matter,²² nitrogen dioxide ("NO₂"), carbon monoxide, ozone, and lead. See 40 C.F.R. §§ 50.4-.12.

In the present case, the parties have stipulated to the attainment classification for the areas where TVA's plants are located during the relevant time. See Regulation Stipulation at 5-6. Based on the Regulation Stipulation, it is undisputed that, during the time when construction was commenced on the physical changes that are at issue in this proceeding, the areas where the Cumberland Plant, the Bull Run Plant, the Kingston Plant, and the John Sevier Plant are located were designated as attainment for NO₂, SO₂, and TSP/PM₁₀. Regulation Stipulation at 6 \ 2. The Allen Plant is located in an area that was classified in 1992 (when construction was commenced on the changes at issue here) as nonattainment for ozone and attainment for NO₂, SO₂, and PM₁₀. Regulation Stipulation at 5-6 ¶ 1. The Colbert Plant is located in an area that was classified in the relevant time frame (1982) as nonattainment for SO₂ and attainment for NO₂ and TSP/PM₁₀. Regulation Stipulation at 6 ¶ 5. The Paradise Plant is located in an area that was classified in the relevant time frame (1985) as nonattainment for SO₂ and TSP and attainment for NO₂. Regulation Stipulation at 6 ¶ 3. The Widows Creek Plant is located in an area that was classified in the relevant time frame (1989) as nonattainment for SO₂ and attainment for NO₂ and TSP/PM₁₀. Regulation Stipulation at 6 ¶ 5. The Shawnee Plant is located in an area that was classified in the relevant time frame (1989 and 1990) as nonattainment for TSP and attainment for NO_2 and SO_2 . Regulation Stipulation at 6 ¶ 4.

2. The NSPS and NSR Statutory Requirements

The CAA prescribes several general methods relevant to this proceeding for protecting and enhancing the nation's air quality, which, as discussed below, become applicable to a particular emissions source if it is "modified" within the meaning of the statute and applicable regulations. The CAA requires the EPA to promulgate NSPSs limiting emissions from sources of air pollution that EPA determines substantially contribute to the endangerment of public health or welfare. CAA § 111(b), 42 U.S.C. § 7411(b). NSPS are technology-based standards set at the emission rate that can be achieved by use of the best adequately demonstrated technology. CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1). After the effective date of an NSPS, owners and operators of "any new source" are prohibited from operating

²¹ Sulfur oxides are to be measured in the air as SO₂. 40 C.F.R. § 50.4(c).

 $^{^{22}}$ In 1971, EPA promulgated primary and secondary NAAQS for particulate matter, measured as total suspended particulate matter, or "TSP." In 1987, EPA promulgated a NAAQS for PM designating particulate matter with an aerodynamic diameter less than 10 microns, or PM_{10} , as a criteria pollutant. Revisions to the National Ambient Air Quality Standards for Particulate Matter, 52 Fed. Reg. 52,634 (1987) (codified at 40 C.F.R. § 50.6). Thus, at different times NAAQS were measured as TSP and PM_{10} .

the source in violation of the applicable NSPS. CAA § 111(e), 42 U.S.C. § 7411(e). "New source" is defined as "any source, the construction or *modification* of which is commenced after the publication of regulations * * * prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2), 42 U.S.C. § 7411(a)(2) (emphasis added). EPA promulgated an NSPS for electric utility steam generating units, which by its terms became applicable to any source that is modified after September 18, 1978. 40 C.F.R. pt. 60, subpt. Da. Thus, if any of TVA's coal-fired steam generating units were "modified" within the meaning of the NSPS provisions on or after September 18, 1978, that unit was required to comply with the NSPS for electric utility steam generating units. As discussed below in Part III.E, EPA Enforcement argues that the changes made to Colbert Unit 5 in 1982-1983 were "modifications" that triggered the NSPS requirements. EPA Enforcement does not allege, in its Post-Hearing Brief, that any other projects triggered the NSPS requirements.²³

In addition, the CAA, in Title I, parts C and D, requires that owners and operators of certain sources of air pollution must obtain permits before beginning "construction," including "modification," of existing pollution sources. This preconstruction permitting requirement is generally referred to as new source review, or NSR. Although the NSPS program is focused on technology requirements for source categories, the NSR requirements focus on the location of the source and its potential effect on the environment of that locality. *Northern Plains Res. Council v. EPA*, 645 F.2d 1349, 1356 (9th Cir. 1981).

There are several types of NSR permitting requirements at issue in this case. Whether a source owner must obtain one of these permits, and which of them must be obtained, depends generally on the amount of air pollution to be emitted from the unit as a result of the modification and the air quality of the area (based on whether the area has or has not attained the NAAQS) in which the source is located at the time of the project. The permitting requirements are pollutant-specific, which means that a facility may emit many air pollutants, but only one or a few may be subject to the permitting requirements. *In re Haw. Elec. Light Co.*, 8 E.A.D. 66, 72 (EAB 1998).

The CAA requires EPA to establish two general types of NSR permitting programs. First, in order to prevent significant deterioration of air quality, the CAA establishes the PSD permitting program which governs preconstruction permitting in areas that are in "attainment" of the NAAQS or are "unclassifiable." See CAA §§ 160-169, 42 U.S.C. §§ 7470-7492. Second, the nonattainment NSR program governs preconstruction permitting in areas that are classified as not in attainment of the NAAQS. See CAA §§ 171-193, 42 U.S.C. §§ 7501-7515. Be-

²³ The Compliance Order also alleged NSPS violations at Paradise Unit 3. As discussed above, EPA Enforcement abandoned those alleged violations in its Post-Hearing Brief.

cause the NAAQS are established on a pollutant specific basis and air quality is assessed with respect to each pollutant, it is possible that a source may be subject to both the PSD permitting requirements and the nonattainment NSR permitting requirements at a single facility if the source is located in an area that is classified as "attainment" for some pollutants, but "nonattainment" with respect to other pollutants.

The CAA provides, with respect to both the PSD program and the nonattainment NSR program, that "modification" of a major stationary source of an air pollutant is unlawful unless the source owner or operator has obtained a preconstruction permit under the applicable PSD or nonattainment NSR program. CAA $\S\S 165(a)$, 169(2)(C), 171(4), 172(b)—(c), 42 U.S.C. $\S\S 7475(a)$, 7479(2)(C), 7501(4), 7502(b)—(c). Specifically, CAA section 165(a) prohibits "construction" of a facility without a permit, and section 169(2)(C) defines construction as including "modification" as defined in section 111(a) of the CAA.²⁴

Before a permit is issued, among other things, the owner or operator of the source must demonstrate, *inter alia*, that post-modification emissions from the source will not violate air quality requirements. Specifically, the owner or operator must demonstrate that "emissions from * * * operation of such facility will not cause, or contribute to, air pollution in excess of [the NAAQS]," among other things. CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3). Further, a permit may not be issued unless "there has been an analysis of any air quality impacts projected for the area as a result of growth associated with such facility." *Id.* § 165(a)(6), 42 U.S.C. § 7410.

3. CAA's Requirement for SIPs (the State Programs)

The CAA contemplates that states may exercise primary responsibility for creating plans to maintain and improve the nation's air quality consistent with the requirements of the CAA. Thus, the CAA calls for states to develop state implementation plans, or SIPs, that provide a plan for attainment of the NAAQs in nonattainment areas and for the prevention of significant deterioration in areas that are already in attainment or unclassifiable. See CAA § 110, 42 U.S.C. § 7410.

In particular, the CAA requires that a state's SIP must "include a program to provide for * * regulation of the *modification* and construction of any stationary source within the areas covered by the plan" to assure that the NAAQS are achieved. CAA § 110(a)(2)(C), 42 U.S.C. § 7410(a)(2)(C), (emphasis added).

Section 172(b)-(c) requires states to adopt SIPs for nonattainment areas that include provisions requiring permits for the construction of new or modified sources, and section 171(4) defines "modified" to have the same meaning as the definition of "modification" set forth in section 111(a).

Sections 110(a) and 161 of the CAA require states to adopt SIPs that contain emission limitations and such other measures as may be necessary to prevent significant deterioration of the air quality in areas that have been designated as "attainment" or "unclassifiable" with respect to the NAAQS. Sections 110(a) and 172 require states to adopt SIPs that, among other things, provide for attainment of the NAAQS in "nonattainment" areas. Thus, states are required to promulgate both PSD and nonattainment NSR permitting programs as part of their SIPs. The CAA also authorizes states to require a third type of permit, known as a minor source permit, which is applicable to all source modifications, whether located in attainment or nonattainment areas. CAA § 110(a)(2), 42 U.S.C. § 7410(a)(2).

Each state's SIP must set forth a permitting program that is at least as stringent as the requirements of the CAA. CAA § 110(a), 42 U.S.C. § 7410(a). EPA is charged with reviewing each state's proposed SIP and determining whether the SIP complies with the CAA's requirements. It must run federal permitting programs governing PSD and nonattainment NSR permitting in states that do not have an approved SIP. CAA § 110(c), (k), 42 U.S.C. § 7410(c), (k). EPA is also authorized to enforce the requirements of states' SIPs. See CAA § 113(a), 42 U.S.C. § 7413(a) (regarding, among other things, administrative orders to comply with SIPs).

In the present case, TVA's plants were, at various times, subject to the federal permitting regulations and at other times were subject to SIP permitting programs run by the States of Alabama, Tennessee, and Kentucky and a local program run by Memphis-Shelby County Air Pollution Control Board. Because this case involves fourteen projects at nine power plants located in three states, and the projects spanned a time period between 1982 and 1996, our discussion of the particular regulatory requirements at issue in this case will take into account the differences in the regulatory language in the different regulatory programs, the changes in those regulatory programs over time, and the changes over time in air quality of the plant locations (which resulted in changes in attainment classification in several areas for particular pollutants).²⁵

²⁵ In brief, the applicable state regulations are: Memphis-Shelby County Air Pollution Control Regulation art. I, div. IV, §§ 16-77, S1200-3-9-.01, 16-46, 16-47, §§ 16-48 (Regulation Stipulation tab 1); Rules of Tennessee Department of Public Health Bureau of Environmental Health Services Division of Air Pollution Control, ch. 1200-3-9-.01, rule 1200-3-2-.01 (Regulation Stipulation tabs 2-5); 401 Kentucky Air Regulations ("KAR") 51:050, 50:010, 51:017 (Regulation Stipulation tabs 6-8, 11-13); Alabama Department of Environmental Management ("ADEM") Regulation 16.4 (Regulation Stipulation tabs 14-15); ADEM Regulation 16.3.2 (Regulation Stipulation tab 15); ADEM Regulation 1.2 (Regulation Stipulation tab 21).

4. The Statutory Definition of "Modification"

Although the particular language of the applicable regulatory program necessarily governs our determination of whether the alleged violations in fact occurred, the PSD, nonattainment NSR, and NSPS violations alleged in this case arise under the same operative language of the CAA: the definition of the term "modification," which, as noted, prescribes what construction activity must have a permit and what construction activity does not require a permit. This same definition of "modification" also defines when an existing source becomes subject to the NSPS requirements. CAA § 111(a)(2), 42 U.S.C. § 7411(a)(2) (defining "new source" as "any stationary source, the construction or modification of which" is commenced after an identified date).

"Modification" for the purposes of the CAA's NSPS, SIP, PSD and nonattainment NSR requirements is defined in the statute as follows:

The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

CAA § 111(a)(4), 42 U.S.C. § 7411(a)(4). For our purposes, this definition contains two primary parts: (1) there must be a "physical change in * * * [a source]" and (2) the change must "increase[] the amount of any air pollutant emitted [by such a source]." WEPCO, 893 F.2d at 907 (quoting 42 U.S.C. § 7411(a)(4)). Thus, the central issues in this case regarding the application of NSR and NSPS requirements relate to whether the projects were physical changes within the meaning of the CAA and the regulations promulgated thereunder, and whether such changes resulted in increases in the amount of air pollutant emissions.

The next part of our discussion will focus on the first of the statutorily-prescribed two part test. We will consider whether the projects undertaken by TVA at nine of its coal-fired electric power plants are "physical changes" within the meaning of the statutory definition and the exceptions adopted by the regulations that implement each of the programs.

The statute also requires a permit before certain "operational changes" are made to a source. See CAA § 111, 42 U.S.C. § 7411. Because this case concerns "physical changes," however, our references to the statute will generally be limited to physical changes.

C. "Physical Change" and the NSR Exclusions for Routine Maintenance, Repair, and Replacement (Both State and Federal)

In this part of our decision, we will focus on the statutory requirement of a "physical change," as interpreted and elaborated upon by the applicable PSD and nonattainment NSR regulations and the case law, and as applied to TVA's projects at issue. In so doing, we will review the regulations that trigger the permitting requirements and examine whether: (1) EPA Enforcement met its *prima facie* case of proving that a "physical change" occurred during each of the projects; and (2) whether TVA met its burden of proving that the routine maintenance, repair, and replacement exception applies to the projects at issue in this case. Finally, we will consider TVA's arguments that EPA Enforcement's application of the rules to the TVA projects implicated by the Compliance Order presents fair notice concerns and represents an impermissible change in Agency interpretation.

1. Was There a Physical Change?

The initial element that EPA Enforcement must prove in its case is that each of TVA's fourteen projects at its nine plants did in fact constitute a "physical change" under the statute.²⁷ While this initial element is not seriously contested in this matter, it is worth noting the nature of the physical changes at the units in question.

In terms of what constitutes a "physical change" within the meaning of the CAA, the Seventh Circuit's holding in *WEPCO* is instructive. There, the court stated that "any physical change means precisely that." *WEPCO*, 893 F.2d at 909. In its decision, the court rejected Wisconsin Electric Power Company's argument that a "simple equipment replacement" did not constitute a physical change for the purpose of the CAA's modification provisions. Instead, the court gave the term "physical change" a broad construction:

Thus, whether the replacement of air heaters and steam drums is a 'basic or fundamental change' in the Port Washington plant is irrelevant for our purposes, given Congress's directions on the subject: 'The

²⁷ In the instant case, the units that are the subject of the Compliance Order have at various times been regulated under a SIP or the federal regulations that apply in the absence of SIP coverage. *See* Regulation Stipulation. In both the federal regulations for NSR and the SIPs for Alabama, Tennessee, and Kentucky, as well as Memphis-Shelby County's local program, the relevant regulatory definitions for "modification," "major modification," and "routine maintenance, repair, and replacement" are substantially the same. Thus, for simplicity, the Board will refer to the federal regulations as representative of all like formulations in its discussion of "physical change." The Board's use of the federal regulations is also consistent with the parties' briefs on this matter. Throughout this reconsideration process, both parties have focused on the federal regulatory language for this first part of the test.

term modification means any physical change * * *.' 42 U.S.C. § 7411(a)(4). We follow Congress's definition of 'modification' — not Webster's — when interpreting this term within the context of the Clean Air Act.

Id. at 907 (citation omitted). In each of the fourteen projects TVA replaced or upgraded substantial boiler components. These components included: horizontal reheaters, economizers, superheaters, secondary superheaters, furnaces, waterwalls, and cyclones. Each project involved the replacement of thousands of feet of tubing. See EPA Enforcement Exs. 202-215; 273, Id. Ex. 279 (Hekking's pre-filed testimony); TVA Ex. 4 (Golden's pre-filed testimony). Recognizing the breadth of the phrase "physical change," TVA's replacement of various boiler components and elements clearly constituted physical changes within the meaning of the CAA.

2. Were the Physical Changes Covered by the Routine Maintenance, Repair, and Replacement Exception?

The regulatory provisions pertaining to physical changes provide a limited number of exceptions to the major modification definition. In this case, TVA has argued that one of these exceptions is applicable to all fourteen projects at issue here. That exception, known generally as the "routine maintenance exception," 28 provides:

A physical change or change in the method of operation shall not include: (a) Routine maintenance, repair, and replacement * * *.

40 C.F.R. §§ 51.165(a)(1)(v)(C), .166(b)(2)(iii), 52.21(b)(2)(iii).²⁹ This exception is not found in the statute, but rather is a creature of regulation, promulgated as part of EPA's NSR regulations in 1978.³⁰ Thus, the second step in our analysis is to consider whether, notwithstanding the presence of physical changes, TVA

²⁸ For ease of reference, we will generally use this phrase to refer to the routine maintenance, repair, and replacement exception.

²⁹ See supra note 25.

The exception originated through the NSPS program, which also includes a similar, but not identical, routine maintenance, repair, and replacement exception. 40 C.F.R. § 60.14(e). "The following shall not be considered modifications under this part: (1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15." 40 C.F.R. § 60.14(e)(1). This NSPS exception, as applicable to Colbert Unit 5, will be discussed below in Part III.E.

can demonstrate³¹ that the physical changes were not subject to NSR because they were excepted as "routine maintenance, repair, and replacement." Although the regulations themselves do not elaborate further on the meaning of the phrase "routine maintenance, repair, and replacement," EPA provided the following guidance in the preamble to its 1992 amendment to the NSR regulations:

[The] determination of whether the repair or replacement of a particular item of equipment is 'routine' under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category.

57 Fed. Reg. 32,314, 32,326 (1992).

TVA and EPA Enforcement differ regarding the proper interpretation of this exception. In considering this interpretive dispute, we look first to the statute itself and its goals. See Auer v. Robbins, 519 U.S. 452 (1997); North Haven Board of Ed. v. Bell, 456 U.S. 512(1982); Georgia v. Shalala, 8 F.3d 1565 (11th Cir. 1993); O'Neal v. Barrow County Bd. of Comm'rs, 980 F.2d 674 (11th Cir. 1993). A major goal of the CAA was to create a program that was technology forcing and that increased the use of air pollution control technology over time. "The Clean Air Amendments were enacted to 'speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again." WEPCO, 893 F.2d at 909 (quoting H.R. Rep. No. 91-1146, at 1, reprinted in 1970 U.S.C.C.A.N. 5356).

In keeping with this objective, the program Congress established was particularly aggressive in its pursuit of state-of-the-art technology at newly constructed sources. At these sources, pollution control methods could be efficiently and cost-effectively engineered into plants at the time of construction. *See* H.R. Rep. No. 95-294, at 185, *reprinted in* 1977 U.S.C.C.A.N. at 1264 ("Building control technology into new plants at time of construction will plainly be less costly then [sic] requiring retrofit"). It was in view of the economic and practical difficulties of retrofitting older, existing plants with modern pollution control devices that Congress in effect "grandfathered" these sources, including the TVA facilities at issue here, from the duty to modernize pollution control.

As the courts have observed, the structure of the Act reflects that this grandfathering was envisioned as a temporary rather than permanent status, in that

³¹ The Board has previously held in its July 3, 2000 Order Regarding the Scope of the Record, the Standard of Review, and Allocation of the Burden of Proof that the routine maintenance exception is an affirmative defense which TVA must raise and with respect to which TVA bears the burdens of production and persuasion. *See* July 3, 2000 Order at 25.

existing plants were required to modernize air pollution controls whenever they were modified in a way that increased emissions. WEPCO, 893 F.2d at 909 ("But Congress did not permanently exempt existing plants from these requirements; section 7411(a)(2) provides that existing plants that have been modified are subject to the Clean Air Act programs at issue here."). Given that existing sources necessarily deteriorate in performance over time, they ultimately must either shutdown or undergo major overhauls to extend their productive life. Since, in the latter case, such major overhauls would often be subject to the requirement to modernize pollution controls, ultimately the environmental protection goals of the CAA would be realized at the vast majority of major sources of air pollution. See WEPCO, 893 F.2d at 909 ("The purpose of the modification rule is to ensure that pollution control measures are undertaken when they can be most effective, at the time of new or modified construction."); Alabama Power, 636 F.2d at 400 (The statutory scheme intends to 'grandfather' existing industries; but the provisions concerning modifications indicate that this is not to constitute a perpetual immunity from all standards under the PSD program. If these plants increase pollution, they will generally need a permit.").

We find additional instruction in the case law pertaining to construction of exceptions. Generally, where, as here, an exclusion is created by regulation, and where the statute does not explicitly contemplate such an exclusion, the exclusion will be narrowly construed. See O'Neal v. Barrow County Bd. of Comm'rs, 980 F.2d 674 (11th Cir. 1993); see also North Haven Bd. of Educ. v. Bell, 456 U.S. 512 (1982). Consistent with this principle of construction, the court in Alabama Power found that EPA's authority to exempt sources from the statutory definition of "modification" is limited to "de minimis [activity] or administrative necessity." Alabama Power, 636 F.2d at 400. The regulatory exceptions to "physical change" promulgated by the Agency in the wake of WEPCO generally reflect this limiting constraint. Indeed, EPA has been mindful of this constraint:

The EPA has always recognized that the definition of physical or operational change in section 111(a)(4) could, standing alone, encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a change in the way that

³² In *Alabama Power*, the court remanded to EPA the Agency's original definition of major modification. The original definition of a major modification included the requirement that the potential emission rate increase by either 100 tons per year or more for any source category identified in the Act (42 U.S.C. § 7479(1)), or by 250 tons per year or more for any stationary source. The court found that EPA had not justified this exemption to the Act of de minimis or administrative necessity and, therefore, struck that portion of the definition. *Alabama Power*, 636 F.2d at 400.

³³ Examples of other exceptions to "physical change" include: use of an alternative fuel by reason of an order or rule under section 125 of the Act; use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste; and any change in ownership at a stationary source. See generally, 40 C.F.R. §§ 51.165(a)(1)(v)(C), .166(b)(2)(iii), 52.21(b)(2)(iii).

pipe is utilized). However, EPA has always recognized that Congress obviously did not intend to make every activity at a source subject to new source requirements.

57 Fed. Reg. 32,314, 32,316 (1992).

The interpretive inquiry at hand cannot be divorced from this statutory and regulatory backdrop; rather, it should be fundamentally informed by it. We turn now to the parties' specific contentions regarding how the routine maintenance exception should be construed in the context of this case. For its part, EPA Enforcement argues that the exclusion requires:

a case-by-case determination by weighing [1] the nature [and] extent, [2] purpose, [3] frequency, and [4] cost of the work, as well as other relevant factors, to arrive at a common-sense finding.

EPA Enforcement Initial Brief at 24.³⁴ As support for its position, EPA Enforcement directs the Board to the Seventh Circuit's discussion of the routine maintenance exception in *WEPCO*. In *WEPCO*, the court unquestionably applied the four factor test³⁵ proposed here by EPA Enforcement in concluding that the particular project under review fell outside the routine maintenance exception. *WEPCO*, 893 F.2d at 910-12.

TVA does not so much take issue with the four factor test advanced by EPA Enforcement and embraced by the court in *WEPCO*, but rather argues that the predominant consideration in applying the four factor test is whether the activity is "common within a relevant source category." TVA Reply Brief at 23. In support of this view, TVA cites, among other things, the preamble to the 1992 amendments to the NSR regulations, which states:

[W]hether the repair or replacement of a particular item of equipment is "routine" under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category.

³⁴ EPA Enforcement's articulation of the test is essentially the same as that articulated in internal Agency guidance from over a decade ago. *See* Memorandum from Don R. Clay, Acting Assistant Administrator for Air and Radiation, U.S. EPA, to David A. Kee, Director of Air an Radiation Division, Region V (Sept. 9, 1988) ("Clay Memorandum"). The Clay Memorandum was cited by the Seventh Circuit in its 1990 decision. *WEPCO*, 893 F.2d at 906.

³⁵ In referencing the test as "the four factor test," we do not intend to discount the possible significance in a given case of the catch-all phrase, "as well as other relevant factors." In this case, however, the evidence fairly neatly arrays itself under the four main factors, thus making it unnecessary to give special consideration to other relevant factors.

57 Fed. Reg. at 32,326 (1992). Thus, in determining whether a project is "routine," TVA's approach looks first to industry practice to determine whether the activity has been undertaken elsewhere. If it has, then, in TVA's view, it should be regarded as routine.

EPA Enforcement acknowledges that the determination of what is routine is necessarily informed by the context of the industry within which a facility operates, see EPA Enforcement Initial Brief at 29, but argues that the fact that a number of facilities within an industry may have undertaken a project which would be viewed as significant in the life of any individual facility does not render such a project "routine" within the meaning of the exception. Rather, according to EPA Enforcement, routineness should be determined according to a broader range of considerations, including, most notably, the significance of the project in the life of the unit in question. Thus, in EPA Enforcement's view, an activity is more likely to be regarded as routine if it is not unusual in the life of a given unit.

TVA's argument ultimately cannot bear scrutiny when set against the structure and objectives of the CAA and the NSR program. As TVA's analysis of the coal-fired utility industry suggests, the coal-fired utility industry is replete with older plants that, to remain productive, have required significant overhauls.³⁶ The reference group to which TVA points is thus one in which a significant number of projects have been undertaken to restore and extend plants' productive lives. If TVA can, under cover of routine maintenance, repair, and replacement, undertake significant, emissions-increasing overhauls of its existing facilities without modernizing pollution controls simply because others in the industry have undertaken like projects, then the CAA's grandfathering of TVA's units in 1977 becomes, in effect, a permanent status. In that event, the natural and efficient occasions that Congress and the courts anticipated for installing modern pollution control equipment, such as where operations are suspended for purposes of reconstructing related equipment, are forfeited.

Given the extent of rehabilitation efforts in TVA's reference group, TVA's construction of the exception would, carried to its logical conclusion, allow TVA to rebuild an entire facility without triggering new source review so long as it did so in increments that can be identified elsewhere in the industry. Indeed, there is evidence that this was an important part of TVA's design. For example, in 1984, a TVA official made the following statement in notes which he typed and submitted to his supervisor after attending an industry life-extension conference. *See* Tr. at 700.

³⁶ At the hearing, as noted *infra*, TVA introduced evidence concerning frequency of boiler component replacements throughout the utility industry.

One statement concerning environmental regulations will need to be kept in mind if massive unit rehab projects are undertaken. If modifications proposed are extensive enough to be considered reconstruction, EPA might try to apply the new source performance standards. This could erase one major advantage of life extension over new plant construction.³⁷

See EPA Enforcement Ex. 139, at 8922750 (Notes from C.F. Dye, Project Manager, Plant Life Extension, Bull Run Steam Plant, to C.N. Dammann, Assistant Director of Fossil and Hydro Power (June 4, 1984)) (emphasis added). This appears to be the kind of "end run" on new source review that concerned the D.C. Circuit in *Alabama Power*, see 636 F.2d at 400 (Congress did not intend that there be "perpetual immunity from all standards under the PSD program"), and that informed the court's conclusion in *WEPCO*.³⁸ Accepting TVA's view risks allowing routine maintenance, repair, and replacement to become the exception that swallows the rule that otherwise requires upgrading of pollution control equipment during modification events. Such an outcome simply cannot be reconciled with the objectives of the CAA.³⁹ See WEPCO, 893 F.2d at 909 (the CAA should not be construed in a manner that would "open vistas of indefinite immunity from the provisions of NSPS and PSD").

TVA's citation to the 1992 preamble and the 1975 NSPS regulatory exclusion cannot serve to resuscitate its interpretation. First, the 1975 NSPS regulations are not applicable to the PSD and nonattainment NSR permitting requirements and, thus, are not relevant in this context.⁴⁰ Second, the language in the 1992 preamble merely explains that in determining whether an activity is "routine," the applicability of the exclusion must be assessed in the context of the particular industry in which the activity is planned. Indeed, the frequency with which certain

³⁷ Although this note refers to reconstruction issues under NSPS, *see* 40 C.F.R. § 60.15, it is nevertheless instructive as to TVA's overall orientation to new source issues.

³⁸ In *WEPCO*, the court approved of EPA's conclusion that if the "purpose is to completely rehabilitate aging power generation units whose capacity has significantly deteriorated over a period of years, thereby restoring their original capacity and substantially extending the period of their utilization as an alternative to retiring them as they approach the end of their life, then the change is not routine." *WEPCO*, 893 F.2d at 911.

³⁹ Where actions in one part of an industry would serve to *categorically* exempt like activities elsewhere in the industry, TVA's argument would also appear to represent a departure from a true *case-by-case* review, as contemplated by Agency guidance and the *WEPCO* decision. Indeed, under TVA's approach, it is questionable whether, in view of the extensive work undertaken within the industry even before promulgation of the 1977 NSR regulations, all of which can be consulted as proof of industry practice, the modification program would have had any meaningful practical effect.

⁴⁰ The NSPS exclusion for routine maintenance, repair, and replacement differs from the NSR exclusion in that the NSPS regulation includes language requiring a determination from the Administrator before the exclusion applies. *See supra* note 30; *infra* Part III.E.

kinds of activities have been undertaken at another comparable plant can be instructive in determining whether, for example, an activity never before undertaken, or seldom undertaken, at a unit under review should be regarded as "routine." But it is the frequency of the activity at other *individual* units within the industry that seems to us most relevant in this context. The mere fact that a number of different facilities within an industry may have undertaken these projects strikes us as much less instructive with respect to whether a project under review should be considered "routine," than the observation that this kind of replacement is, for an individual unit, an unusual or once or twice-in-a-lifetime occurrence. Further, we find nothing in the 1992 preamble passage that supports TVA's view that such information should be treated as dispositive of routineness.

Notably, in *WEPCO*, the fact that the project had never been done by another entity in the industry was certainly a factor the court referenced. However, the court did not stop its analysis there. Rather, the court cited additional facts as significant in its finding the project to be non-routine, including, "the renovation work items * * * are those that would normally occur only once or twice during a *unit's* expected life cycle." *WEPCO*, 893 F.2d at 912 (emphasis added).

Thus, in our view, the approach advocated by EPA Enforcement more reasonably implements the statutory objectives and the regulatory text in question. See Fluor v. OSHA, 861 F.2d 936, 941 (6th Cir. 1988) ("[T]he Commission's interpretation of the regulation better serves the remedial purposes of the [Act].") Unlike TVA's construction, which tends to elevate a single consideration — the occurrence of an activity anywhere else within an industry — above all others, EPA Enforcement's approach examines the full range of considerations contemplated by the four factor test historically embraced by the Agency and adopted by the court in WEPCO.

We further find this articulation more consonant with the principle, discussed above, that the exclusion be *narrowly* construed in light of the statutory intent, regulatory construction, and prior case law, including, most notably, the requirement that any regulatory exemption be applied to exclude only "de minimis" activity or for "administrative necessity." *Alabama Power*, 636 F.2d at 400.

We move now to the application of the four factor test to the projects addressed by EPA Enforcement's Compliance Order to determine whether TVA has met its burden of showing that they are routine. To provide context, we first consider a number of preliminary matters, including background information on the nature of facilities affected by the projects at issue, and information regarding TVA's organizational structure and accounting practices that bears on the question of routineness.

- 3. Application of Routine Maintenance Exception to TVA's Projects
 - a. Description of the Coal-fired Production of Electricity

The fourteen projects at issue in this case deal mainly with the boilers in nine of TVA's coal-fired plants. Accordingly, some background regarding how the utility industry uses boilers in the generation of electricity and a more detailed description of a typical boiler unit is helpful before discussing the particular changes TVA made to the units at issue in this case.

Each plant that uses coal in the production of electricity has three main sections used to convert the energy from coal into electrical energy: (1) the boiler, (2) the steam turbine, and (3) the electric generator. Tr. at 52. Each of these sections of the plant is used in one stage of the conversion from coal to electricity. The boiler performs two main functions in this process. This is where (1) coal is combusted and the coal's energy is released in the form of heat and light and (2) heat energy is converted into steam energy. The steam is then directed to the turbine where it is further converted to mechanical energy in the form of a spinning turbine shaft, which in turn drives the generator that produces the electricity. Tr. at 53.

Boilers range in size from a few stories to twelve stories high. Tr. at 54. In general, a boiler is constructed of miles of tubing or piping. Tr. at 53. The walls, roof, and floor are comprised of pipes or tubes, as are the other major components in a boiler. The latter components are suspended within the boiler unit itself and include, for example, the economizer, reheater, primary reheater, primary superheater, secondary superheater, and secondary reheater. Additionally, burners are attached to the boiler. TVA uses cyclone burners⁴¹ at many of its units. The number of burners at a boiler depends on the size of the boiler.

The combustion process generally works as follows. After the coal is ground to the appropriate size for the burners, air suspends the particles and transports them to the burners. Once the coal is ignited in the furnace, it releases energy, gas by-products, and particulate matter or PM. The gases are collectively referred to as the flue gas.⁴²

⁴¹ TVA uses cyclone burners at many of its units. The burners are attached to the boiler and are used in the coal combustion process.

 $^{^{42}}$ The gases produced from the combustion process form carbon dioxide, carbon monoxide, SO_2 , and NO_X . Tr. at 63. The flue gases flow through the upper sections of the boiler and exit to the air preheater and then generally to an air pollution control device. From the pollution control equipment the gas enters an induced draft fan, then out the stack and is emitted into the atmosphere. Tr. at 64-65.

The various components of the boiler are involved in the absorption process which transfers the heat energy of the coal to steam. The tubes or pipes which form the walls of the boiler are called waterwalls and contain mostly water. The components that are suspended inside the boiler contain mostly steam. The hot gases travel between the pipes that make up these components so that heat energy is absorbed from the flue gases and transferred to the steam contained inside the pipes. Although the exact position of these components varies from one boiler to the next, they function in largely the same manner in all boilers. In short, these components allow the transfer of heat energy from the combusted coal to the steam in the piping.

Because the pipes that comprise the waterwalls and suspended components are in constant contact with the flue gas and/or combusting coal, those pipes are subject to deterioration over the life of the boiler and may develop leaks and require repair, or replacement. As will be discussed below, the projects at issue in this case do not involve the replacement or repair, of an occasional or isolated broken or ruptured pipe, but instead involve the replacement of multiple components, each of which consists of tens of thousands of feet of pipe that had deteriorated to a point where breaks and ruptures had become frequent, substantially impairing TVA's ability to run the boiler.

b. TVA's Long Term Planning

TVA's historical plans and strategies for creating and maintaining a power supply for its customers provide context for the fourteen TVA projects currently at issue. Throughout the 1960s and 1970s, TVA saw demand for electricity grow. To meet this demand, TVA began planning and constructing seventeen new nuclear power plants. EPA Enforcement Exs. 201; 279, at 3 (Hekking's pre-filed testimony). However, in the late 1970s, TVA's strategy changed dramatically when demand for electricity unexpectedly declined and public support for nuclear power waned. EPA Enforcement Ex. 279, at 3; Tr. at 129. Instead of relying on newly constructed nuclear plants, TVA decided to extend the lives of the coal-fired units originally intended to be replaced by the new nuclear plants. EPA Enforcement Ex. 201. TVA eventually abandoned its nuclear plant construction plans and focused primarily on its older coal-fired units. A 1987 report written by two of TVA's employees for the Electric Power Research Institute describes TVA's strategy:

The coal-fired units that were expected to be replaced by those cancelled nuclear units will now have to be used at least for the rest of this century. This will require continued reliable operation of all coalfired units now in service.

If 40 years is assumed to be the useful life of a coal-fired unit, after which the unit would be retired, the oldest TVA plant would retire in

1991. By the year 2000 all 50 units of less than 500 MW would be retired, removing a total of 8,250 MW from the system generating capacity. * * * [This] illustrate[s] the need for a comprehensive program to address what is required for each unit to make the equipment perform reliably for another 20 years or more under predicted operating conditions. This program was called the Fossil and Hydro Unit Evaluation and Modernization Program (FHUEM).

EPA Enforcement Ex. 201, at 853-54. The goals of the FHUEM program, which TVA began in 1984, were:

(1) to extend plant life 20 or more years beyond its design life of 35 to 40 years, (2) to maintain unit reliability and efficiency, and (3) to modernize by utilizing advanced technology.

EPA Enforcement Ex. 201, at 854. The program was not implemented as originally designed in large part because of the expense and the length of time each unit would be shut down for the replacement. See EPA Enforcement Ex. 279, at 4-5 (Hekking's pre-filed testimony). However, this program did identify particular components at TVA's coal-fired plants that would require replacement because those components were at the end of their useful lives. Id. TVA incorporated its findings under the FHUEM program into its ongoing "Capital Additions and Improvements Program," as discussed more fully below. Id. The program was used to fund the replacement of major equipment and their components.

c. TVA's Organization and Operation

Before discussing the physical changes made by TVA to the boilers, it is also useful to have a better understanding of how TVA conducted its operations, especially with respect to its procedures and accounting practices pertaining to construction activities at individual units. At the hearing, EPA Enforcement put two former TVA employees on the stand, Mr. Hekking and Mr. Donald Randolph, who both testified regarding TVA's operations and organization. Tr. at 101-325.

From 1978-1988, TVA had a single division for its coal-fired plants and the hydro plants, the Fossil and Hydro Power Division, within which there was a separate group for the coal-fired plants. *See* EPA Enforcement Ex. 230 ("TVA Fossil & Hydro Organization"). Responsibilities for the coal fired-plants were allocated between the individual plants and the central office in Chattanooga as outlined below.

i. Operations at the Plants

At each coal-fired plant, TVA established three primary departments — operations, results, and maintenance. *Id.* The operations department ran the plant, the results department ensured efficiency of the plant, and the maintenance department was responsible for daily maintenance and work necessitated when forced outages occurred. Tr. at 109. Mr. Randolph described the plants' maintenance department duties as follows:

[T]he plant maintenance department was primarily responsible for the running maintenance, routine maintenance to keep the plant going. They had all crafts people. They had a few engineers, and they dealt with the day-to-day maintenance problems at the plant.

Tr. at 110. Among the kinds of projects that each plant's maintenance department would perform were such items as fixing a valve leak and replacing a failed tube. *Id.*

ii. TVA's Central Office

TVA also had a central office in Chattanooga that contained, among others, a plant maintenance branch. The plant maintenance branch of the central office coordinated with the maintenance departments at the plants on major replacement projects that the plant's maintenance staff alone could not undertake. Tr. at 114. Mr. Randolph characterized the role of the central office's plant maintenance group by stating: "[W]e functioned primarily like a contractor to the plant, only we were an in-house contractor." Tr. at 119.

Within the central office plant maintenance branch was a boiler and auxiliaries ("boiler") group, which was further subdivided into several sections. The engineering section of the boiler group was responsible for assessing boiler problems. Among other responsibilities, it would prepare the necessary paperwork to initiate large construction projects that the maintenance department at an individual plant could not handle. Tr. at 115. High level management approval at the central office was required before any such project could proceed. Tr. at 118. The required approval levels for each project varied depending on the project cost. EPA Enforcement Ex. 279, at 15 (Hekking pre-filed testimony). In the 1980s, TVA required approval by its Board of Directors on all projects over \$1 million. *Id.* In the 1990s, Board approval was required for projects over \$2.5 million. *Id.*

Following approval of a project, a field supervisor from the construction section, which was also a part of the boiler group, would be assigned to oversee each project. The construction section was responsible for hiring additional craftsmen needed for each particular project and for overall project implementation. Tr. at 119.

In 1988, TVA reorganized in a way that, among other things, affected the construction section. Thereafter, when the planning and approval of a project was completed, the project was transferred to a new division, the Fossil and Hydro Modification Division, for implementation. Tr. at 123-24.

iii. The Central Office's Control of These Projects

As described above and outlined in more detail below, TVA distinguished between projects by placing responsibility for larger construction projects with the central office, while leaving responsibility for smaller projects to each plant's maintenance department. As discussed below, all of the projects at issue in this case were ultimately handled, not by the plant's maintenance department, but by the central office's plant maintenance department. In essence, these were among the largest projects undertaken by TVA at its coal-fired power plants.

d. TVA's Budgets

Not only did TVA distinguish between projects by placing responsibility for the larger construction projects with the central office, but TVA's operations further differentiated between projects through the budgeting process. The yearly operation and maintenance budget ("O & M budget") for each plant was used for any projects undertaken by a plant's maintenance department, while the projects planned and implemented by the central office's plant maintenance branch used money in the capital budget. *See* Tr. at 112, 120. From the record, it appears that the two budgets — the O & M budget and the capital budget — were distinct from one another. Tr. at 120-21.

As early as the 1970s, TVA had a capital additions and improvements ("Capital A & I") program. TVA used this program to fund "replacement of major equipment and some of their components." EPA Enforcement Ex. 279, at 14. TVA's own policy for distinguishing between capital projects (the Capital A & I budget) and maintenance projects (O & M budget), known as its Capitalization Policy, is enlightening:

In general, projects which add new tangible assets or leave existing tangible assets in better condition for profitable service than when new are given a capital classification (e.g., increase capacity, efficiency, or useful life.) Projects which only restore tangible assets to a former serviceable condition are maintenance.

EPA Enforcement Ex. 152. TVA's Capitalization Policy goes on to further define what is not a capital project:

A capital classification is *not* given to projects that: inspect, test, assess, and report on the condition of existing tangible assets specifically to determine the need for repairs, replacements, and rearrangements; prevent failure, *restore serviceability*, or *maintain useful life* of existing tangible assets; rearrange or change the location of existing tangible assets; repair or restore existing tangible assets for reuse * * *

Id. (emphasis added). When TVA classified a project as a capital project, TVA recognized that the project added a new tangible asset or left an existing tangible asset in an improved condition. Thus, under TVA's classification policy, TVA's classification is directly relevant to the purpose of the project — to improve the unit, rather than simply maintain the status quo.

e. The Projects

With this as background, we now apply the four factor test EPA historically has used, and which was upheld by the court in *WEPCO*, to the projects at issue in this case. For ease of reference, we have incorporated into this decision in general form EPA Enforcement Ex. 273, which gives a general description of the fourteen projects.⁴³

⁴³ The essence of this exhibit was not seriously contested by TVA.

TVA COAL-FIRED PLANT PROJECTS

Plant/Unit/Date in Service	Project	Cost	End Date
Allen #3 (1959) 330 MW	Redesigned and replaced horizontal reheater. Outage: 3 months.	\$10.78 million	1992-93
Bull Run #1 (1967) 900 MW	Replaced economizer and secondary superheater spaced outlet sections in each of 2 furnaces. Outage: 3 months.	\$8.3 mil- lion	1988
Colbert #5 (1965) 500 MW	Replaced waterwalls and horizontal reheater, modification to the startup system, added wingwalls in the furnace, replaced gas proportioning dampers, replaced windbox, redesigned and replaced control system, and added balanced draft conversion. Outage: 13 months.	\$57.1 million	1982-83
Cumberland #1 (1973) 1300 MW	Replaced and redesigned secondary superheater outlet headers, replaced secondary superheater pendant elements and replaced lower slope and lower waterwalls. Outage: 3 months.	\$22.91 million	1996
Cumberland #2 (1973) 1300 MW	Replaced and redesigned secondary superheater outlet headers, replaced secondary superheater pendant elements and replaced lower slope and lower waterwalls. Outage: 3 months.	\$18.41 million	1994
John Sevier #3 (1956) 135 MW	Replaced superheater platen elements, all burner tube panels in both furnaces, and waterwalls in front, rear, and sidewalls of both furnaces. Outage: 2.5 months.	\$3.94 million	1986

Plant/Unit/Date in Service	Project	Cost	End Date
Kingston #6 (1955) 200 MW	Replaced all reheater and superheater intermediate pendant elements, waterwalls of superheater and reheater furnaces. Outage: 2 months.	\$2.6 mil- lion	1989
Kingston #8 (1955) 200 MW	Replaced all reheater and superheater intermediate pendant elements, waterwalls of superheater and reheater furnaces. Outage: 3 months.	\$2.9 mil- lion	1989-90
Paradise #1 (1963) 770 MW	Replaced all 14 cyclones and lower furnace walls, floor and headers. Outage 6.5 months.	\$16.3 million	1985
Paradise #2 (1963) 770 MW	Replaced all 14 cyclones, lower furnace walls, floor and headers. Outage: 4.5 months.	\$15.79 million	1985- 1986
Paradise #3 (1970) 1150 MW	Replaced all 23 cyclones and lower furnace walls, floor and headers. Outage: 6 months.	\$29.44 million	1985
Shawnee #1 (1953) 175 MW	Replaced secondary super- heater and reheater pendant elements and crossover ele- ments, including header stubs. Outage: 3 months.	\$4.5 mil- lion	1989-90
Shawnee #4 (1953) 175 MW	Replaced secondary super- heater and reheater pendant elements and crossover ele- ments, including header stubs. Outage: 2 months.	\$5.1 mil- lion	1990
Widows Creek #5 (1954) 141 MW	Replaced secondary superheater and crossover elements, and reheater and crossover elements. Outage: 4 months.	\$4.13 million	1989-90

In the discussion that follows, we cite to the facts in the record that are most significant in determining whether TVA's projects were routine maintenance, repair, and replacement using the four factor approach identified above. We further address the main points that EPA Enforcement and TVA raise in support of their respective arguments.

On balance, as indicated below, we conclude that TVA has not met its burden of establishing by a preponderance of the evidence that the nature and extent, purpose, frequency, and cost of these projects was such that they fell within the regulatory exception for routine maintenance, repair, or replacement.⁴⁴ Our judgment is informed by all the evidence in the record, the totality of which is insufficient to establish that these projects properly fall within the scope of this exception.

Our general findings under the four factor test are stated below. Further detail regarding our findings on a project-by-project basis can be discerned from Appendix A to this decision, which catalogues our findings for each of the fourteen projects in question. In finding that TVA has failed to carry its burden of proving that its projects fall within the exception for routine maintenance, repair, and replacement, we find material the following facts:

1. Nature and Extent

- The construction activities involved in these projects affected significant boiler components and typically was massive, including in some cases the construction of onsite railroads and monorails and the replacement of miles (in one instance 67 miles) of tubing.
- TVA's central office, including staff from its construction and (after 1988) modification group developed and carried out the projects, rather than the maintenance department located at each plant.
- The projects took many years to plan, in most cases well beyond the time associated with planning TVA's scheduled maintenance outages which took place approximately every eighteen months. Moreover, these projects required TVA's Board of Director's approval, whereas plant managers approved the projects handled by the maintenance departments at TVA's plants. Tr. at 112.

While we have held that TVA bears the burden of proof on this issue, we do not see our conclusion here as hinging on our burden of proof ruling. Indeed, the evidence is such that, even if EPA Enforcement had the burdens of production and persuasion to establish that each of the fourteen projects did not constitute routine maintenance, repair, or replacement, those burdens would be met.

Implementation of the projects required plant shutdowns of many months (ranging from two to thirteen months), substantially in excess of the time period typically associated with forced outages which lasted a few hours to five days. Significantly, these projects also required substantially more time to complete than was typically required for TVA's scheduled maintenance outages which occurred every eighteen months and usually required the shutdown of a unit for approximately four weeks. See Tr. at 225.

2. Purpose

- The purpose of the projects generally was to significantly extend the life of the unit in question by as much as twenty years.
- All projects were classified as "capital" rather than as "maintenance" projects. TVA's Capitalization Policy provides such classification for projects that add tangible new assets or leave existing assets in "better condition" than when the original asset was installed for profitable service, but defines as maintenance projects those projects that merely restore tangible assets to serviceability.⁴⁵

⁴⁵ The Board has reviewed TVA's arguments against using the capital classification as a relevant factor in evaluating whether the projects fall within the routine maintenance exception. TVA argues that:

[[]its] decisions with respect to accounting for plant-related expenditures are based on the application of generally accepted accounting principles ("GAAP") and the accounting guidelines promulgated by the Federal Energy Regulatory Commission ("FERC") under the Uniform System of Accounts ("USoA"). * * * Neither GAAP nor the USoA provide a working definition of "routine" for purposes of accounting for plant-related expenditures.

TVA Post-Hearing Brief at 36-37. We agree that, by itself, the capital classification would not determine what activities are or are not "routine" under NSR. However, due in large part to TVA's own distinction between the capital and maintenance classification in its Capitalization Policy, see EPA Enforcement Ex. 152, which is consistent with the FERC USoA rules, we believe the designation does provide some insight into the purpose, as well as the nature and extent, of the projects since TVA's classification recognized whether a project was intended to improve a unit or merely maintain it. See EPA Enforcement Ex. 152. Furthermore, in determining whether each project falls within the scope of the routine maintenance exception, our review not only looks at whether TVA classified a project as a capital project, but also looks to other related facts in the record. Thus, in the TVA context, large capital projects were centrally managed, required years of planning, and required high-level approval. Collectively, this information bears on our determination whether the projects are "routine" under NSR.

3. Frequency

- As in the WEPCO case, these replacements had generally never before been performed on these units and were considered to be rare replacements for such units.
- Although TVA introduced evidence that it and others in the industry had
 made similar replacements at other facilities, the evidence did not show that
 these replacements were other than uncommon in the lifetime of a unit.

4. Cost

- All projects cost in excess of \$2.5 million (ranging from \$2.6 million to \$57.1 million) and required approval of TVA's Board of Directors. 46
- The cost of implementing these projects would have consumed most of each plant's O & M budget and in some cases would have exceeded the plant's O & M budget.

TVA disputes a number of these considerations. For example, TVA disputes the relevance of its division of responsibility between its plants and the central office.⁴⁷ Particularly, TVA argues that it chose to centralize certain duties for efficiency and, therefore, the fact that the projects at issue were managed by its central office is irrelevant to the determination of a project's routineness. Since the size of the project appears to bear materially on the decision whether to man-

⁴⁶ The Board has generally not relied on the testimony given by Mr. Michael Majoros, an EPA Enforcement witness, regarding the relative costs of each project to the unit's original cost. TVA objected to his analysis. We find TVA's objection to this aspect of his testimony to be generally valid since Mr. Majoros compared only "nominal" dollar, not real dollar values in all except two projects. This being said, we did not find the evidence adduced by TVA regarding relative costs to be particularly helpful either. TVA compared the cost of each project for a single boiler to the cost of the plant's entire boiler system, which contains many units.

Mr. Majoros did convert the dollars for Shawnee Unit 1 and Paradise Unit 1 from nominal to real dollars. We find Mr. Majoros' testimony useful in these instances, and, after reviewing the record, are in these instances unconvinced as to TVA's charge that his testimony is inaccurate. After Mr. Majoros corrected his reference to Account 312, and instead referred to Plant Unit Number ("PUN") 167-1, his testimony appears accurate. Indeed, TVA's accountant, James Callahan, testified that Mr. Majoros' numbers appeared accurate. Tr. at 886-87.

⁴⁷ In its Post-Hearing Brief, TVA argues that its use of central office staff in implementing these projects is not a relevant fact in determining whether those projects are routine since plant maintenance staff were also used on capital projects. TVA Post-Hearing Brief at 23. However, in reviewing the record in the matter, the Board finds persuasive the fact that use of plant maintenance personnel for capital projects occurred only with "small capital projects" and that the larger construction projects were handled by TVA's central office. *See* Tr. at 195. Thus, TVA distinguished between projects of a certain magnitude and scope.

age the project out of the central office, and smaller projects were generally thought of as "running or routine maintenance" and given to the plant's maintenance department to undertake, we cannot agree that this consideration is irrelevant. While this consideration alone may not be dispositive, taken in conjunction with other facts, it does support a finding that the projects under review here are outside the routine maintenance exception.

TVA also takes issue with EPA Enforcement's use of the length of time TVA took to plan each project. TVA argues that since the WEPCO court did not use this fact in deciding the WEPCO project was nonroutine, EPA Enforcement should not use this fact either. We believe the length of time a project takes to plan and approve can be relevant to the four factor test because it goes directly to the nature and extent of the project. Where, as here, project planning takes months, sometimes years, beyond the planning necessary for regular, ongoing maintenance, this fact creates an inference that the project is not "routine" because such a long planning and approval process is needed.

As discussed more fully below, TVA's principal defense — that it had become common practice at TVA and generally within the industry and thus "routine" in this industry, to make such once or twice-in-a-lifetime replacements — is alone not enough to carry TVA's burden to establish that these projects fit within the narrow regulatory exception for routine maintenance, repair, and replacement. Nor are we persuaded that only replacements of the magnitude of those at issue in *WEPCO* are outside the scope of the routine maintenance exception. As EPA argues persuasively, *WEPCO* did not set a minimum floor below which a project comes within the scope of the exception. Rather, the determination is made on a case-by-case basis applying a reasonable test which evaluates nature and extent, purpose, frequency, and cost.

In approaching the question of what is routine, there is nothing in the regulatory history of the routine maintenance exception that calls for us to leave common sense behind. The testimony at the hearing of two former TVA officials⁴⁸ lends striking support for the common sense test that we are following. Donald

⁴⁸ During his fifteen years with TVA, Mr. Randolph held various positions including: section supervisor of the valve and heat exchanger section in the plant equipment branch of the Fossil and Hydro Power Division at the central office, and manager of the plant boiler equipment department within the same division. Mr. Randolph is currently self-employed as a consulting engineer and analyzes failures and welding problems. Tr. at 102-07.

During Mr. Hekking's twenty years at TVA he held various positions and titles including: mechanical maintenance supervisor at the Johnsonville Plant, assistant plant superintendent at the Allen plant, plant manager at the Allen plant, and an interim position as manager of fossil operations. Mr. Hekking currently works for the Memphis and Shelby County Health Department as a supervisor of the Title V/Major Source Group in Pollution Control and as an independent consultant for EPA Enforcement in this matter. EPA Enforcement Ex. 279, at 1; Tr. at 264-265.

Randolph, former manager of TVA's central Boiler Equipment Section and an employee of TVA for over fifteen years, and Alan Hekking, a former TVA plant manager and an employee of TVA for more than twenty years, both testified that projects of the kind at issue in this case were not "routine maintenance" in their understanding of that term.⁴⁹ For example, on cross-examination, Mr. Randolph testified as follows:

Q. Now, if you assume that routine means customary in the industry, standard operating procedure, would you then agree that it is a routine maintenance strategy in the industry and for TVA to perform the type of maintenance, repair, and replacement that we have been discussing here by TVA?

A. I do not consider these major replacement projects routine maintenance. That [sic] is *major* maintenance projects.

* * * * * * *

Q. Would you agree here that routine improvement refers to, in this particular case, a routine replacement to TVA?

A. The problem I would have with that, this is the first time in 36 years and it is hard for me to say that is routine.

Tr. at 192-93, 196-97. Mr. Hekking had a complementary view. On direct, he testified as follows:

Q. When this project [Allen Unit 3] was implemented back in 1992 and 1993, Mr. Hekking, did the Tennessee Valley Authority consider this project to be routine maintenance or routine repair or routine replacement?

A. No, sir.

Q. Can you tell us why?

A. A number of reasons. * * * The money spent on this one project alone exceeded my annual budget. I think that is one reason it wasn't routine. It was performed during an outage. I told you that a routine scheduled outage for us was four weeks. This was a 12-week outage.

⁴⁹ TVA has attempted to discount Mr. Randolph's and Mr. Hekking's testimony on the question of what is routine by pointing out that each had prepared a planning report for a capital project which checked in the affirmative a box stating, "Routine Improvement of Existing TVA Facilities." According to TVA, this reflected that these witnesses had changed their interpretation of routine maintenance over time. TVA Post-Hearing Brief at 17-19. Mr. Hekking was not asked about the alleged inconsistency in cross-examination. Mr. Randolph was, however, and refused to equate "routine improvement" with "routine maintenance." Given this fact, and the fact that it is not apparent to us that these are, in fact, equivalent terms, we are not inclined to disregard the testimony of these witnesses.

That was not routine. The reheater that we put back in, we replaced an entire component. It wasn't a tube or several tubes or couple of elbows, it was an entire component, a large component. That was not routine.

Tr. at 246-47. On cross-examination, Mr. Hekking continued:

Q. In your opinion does the number of reheaters replaced in the industry, let's say — let's talk about reheaters because that's what you talked about at the Allen plant. Let's say that there were 100 reheaters replaced in the entire industry or 200 or 300 or 500; does that make it routine maintenance or routine replacement?

A. No sir. If it's replaced once in its lifetime of 30 years, that's not routine.

Tr. at 324.50

As we have said, we do not believe that Congress in the statute or EPA in its underlying regulations excluded such carefully planned, massive rebuilding efforts from the requirements to obtain a permit and put on appropriate pollution controls. Although numerous activities properly fall within the exception for routine maintenance, repair, and replacement,⁵¹ to conclude that these activities are within its scope would stretch the exception beyond reason. For these kinds of physical changes at existing facilities, Congress made a judgment that in order for the projects to proceed they must be balanced with careful up-front review designed to protect the environment. It is hardly surprising that where, as here, major changes are being made to the boiler, modifications can simultaneously be made to the boiler's flue gas ducts, where the pollution control equipment is typi-

⁵⁰ For its part, TVA's witnesses, e.g., Jerry Golden and Gordon Parks, offered the view that these projects were routine principally because they had been undertaken elsewhere in the industry. See TVA Ex. 4. They did not refute Mr. Randolph's and Mr. Hekking's premise that the projects under review here were highly unusual in the life of a given unit and fell outside the scope of regular maintenance practice at individual units.

⁵¹ The record supports the conclusion that activities undertaken in short-term forced outages (typically five days or less) and most maintenance undertaken as part of regular planned maintenance outages (four-week outages occurring every eighteen months) will typically fall within the ambit of "routine." *See, e.g.*, Tr. at 109-10, 242-43. For example, in characterizing the kind of routine maintenance undertaken by plant maintenance staff, Mr. Randolph stated as follows:

There was all kinds of stuff. * * * [I]f a valve started leaking, it would be up to them to repack that valve, maintain it, get it back into the proper order. If the boiler went into emergency outage, forced outage, boiler tube ruptured, blew, it would be up to them and when the unit came off-line to get in there, cut that tube out, put a Dutchman or replacement tube in, and get it repaired and get back on-line.

cally located. Accordingly, these modification projects are a natural and efficient occasion to upgrade pollution control equipment. Any other result would, in our view, constitute a "perpetual immunity" for existing plants, a result flatly rejected by Congress and the circuit courts in *Alabama Power* and *WEPCO*.

In sum, the Board finds, based on its application of the four factor test — nature and extent, purpose, frequency, and cost — to the evidence in the record of this case, that none of the fourteen projects before the Board qualifies for the routine maintenance exception.⁵²

4. Fair Notice and Rulemaking Arguments

TVA raises two defenses to the application of the exception for routine maintenance, repair, and replacement, as we are interpreting that phrase. First, TVA argues that it did not have fair notice of this interpretation because it was not "ascertainably certain" either from the regulations themselves, or from EPA's statements regarding those regulations. TVA Post Hearing Brief at 91-98. Further, TVA argues that EPA has changed its interpretation of the routine maintenance, repair, and replacement exception without the requisite notice and comment rulemaking and that retroactive application of EPA's new interpretation would be unfair, given TVA's alleged reliance on EPA's prior interpretation in performing the projects. *Id.* at 44-46. For these reasons, TVA argues, the Board must withdraw the Compliance Order.

a. Fair Notice

TVA argues that EPA's interpretation of the regulatory exception was not "ascertainably certain" and did not provide TVA with fair notice. See TVA Post-Hearing Brief at 81-106. Accordingly, based on the case law discussing the need for fair notice in the regulatory arena, TVA concludes that it cannot be liable for violating any preconstruction permitting requirements of the Act. For the following reasons, TVA's contention that it lacked fair notice must be rejected.

The Supreme Court has stated, "[R]egulations affecting only economic interests must be sufficiently definite so that ordinary people exercising common sense will know what they mean." *Boyce Motor Lines v. United States*, 342 U.S. 337, 340 (1952). In further expressing the idea of the need for fair notice to the regulated community, the D.C. Circuit has observed:

[W]e must ask whether the regulated party received, or should have received, notice of the agency's interpretation in the most obvious way of all: by the reading of the regulations. If, by reviewing the reg-

⁵² See supra Part III.C.3.e (summary of our findings).

ulations and other public statements issued by the agency, a regulated party acting in good faith would be able to identify, with 'ascertainable certainty,' the standards with which the agency expects parties to conform, then the agency has fairly notified a petitioner of the agency's interpretation.

General Elec. Co. v. EPA, 53 F.3d 1324, 1329 (D.C. Cir. 1995).

Significantly, providing fair notice does not mean that a regulation must be altogether free from ambiguity. Indeed, the case law shows that even where regulatory ambiguity exists, the regulations can still satisfy due process considerations. See, e.g., Texas Eastern Prod. Pipeline Co. v. OSHA, 827 F.2d 46 (7th Cir. 1987). In this regard, the D.C. Circuit has observed:

While interests furthered by the Due Process Clause and the First Amendment favor such regulation by bright lines, we are quite unprepared to hold that the Due Process Clause prohibits a contextual regulation. Reading such a requirement into the Clause would likely invalidate most criminal statutes and administrative regulations.

United States v. Thomas, 864 F.2d 188, 198 (D.C. Cir. 1988). Thus, the question is not whether a regulation is susceptible to only one possible interpretation, but rather, whether the particular interpretation advanced by the regulator was ascertainable by the regulated community.

In its prior cases examining such issues, the Board has stated that in determining whether notice has occurred one should first look to the language of the regulations. "[T]he analysis would next proceed to a determination of whether the Region's interpretation embodied in the rule or statement was reasonable in light of the language of the regulation and the overall structure of the regulatory scheme." In re CWM Servs., Inc., 6 E.A.D. 1, 18 n.28 (EAB 1995); see also In re B.J. Carney Indus., 7 E.A.D. 171, 195 (EAB 1997) (holding that the regulatory definition of "process wastewater" is sufficiently clear to give an ordinary person reasonable notice of prohibited conduct), 192 F.3d 917 (9th Cir. 1999), vacated as moot, 200 F.3d 1222 (9th Cir. 2000); In re V-1 Oil Co., 8 E.A.D. 729, 751-53 (EAB 2000) (applying standards set forth in Gen. Elec. Co., 53 F.3d at 1329, to reject fair notice affirmative defense). Accordingly, we regard the statutory and regulatory context within which a regulation was promulgated as highly instructive in determining whether a meaning ascribed to the regulation was ascertainable.

In the present case, TVA states that EPA's further statements on the subject, particularly in the form of the NSPS exception for routine maintenance and the preamble to the 1992 amendments to the NSR rule, did not communicate the interpretation that EPA Enforcement is embracing in this case with "ascertainable

certainty." Additionally, TVA cites to the privilege log,⁵³ produced by EPA Enforcement for this matter, to infer that because EPA Enforcement asserts a deliberative process privilege over certain documents pertaining to the exception, there must be continuing uncertainty regarding the interpretation inside the Agency. If EPA itself is uncertain about its meaning, then surely, according to TVA, its interpretation could not have been ascertainable by the regulated community. *See* TVA Post-Hearing Brief at 97-99.

We have difficulty accepting TVA's premise that the regulatory text fails to adequately put the regulated community on notice of the interpretation that we are following here. As discussed in Part III.C.2, when the context within which this regulatory exception rests is considered, the interpretation that we are following is not at all difficult to distill. As we have discussed at length, this context includes Congress' sweeping coverage under the CAA of "any physical change" (emphasis added) at existing facilities; the fact that this exception is expressly provided for only by the regulations, not the text of the Act; Alabama Power's holding that regulatory exclusions under the NSR program were available to the Agency only where it could demonstrate the exempted activity was de minimis or of administrative necessity; and the notion articulated in Alabama Power and WEPCO that the grandfathering accorded existing sources was not intended to allow "perpetual immunity" from NSR. TVA was hardly unaware of this context. To the contrary, it is a sophisticated entity, represented by experienced counsel that has actively participated in rulemaking, and other activities pertaining to the CAA. See Tr. at 711-13; EPA Enforcement Post-hearing Brief, Attach. J and K.⁵⁴

As we have also discussed, by contrast, the alternative interpretation that TVA advances, which looks to whether a project has been undertaken elsewhere in the industry or in any one of TVA's plants, is fundamentally at odds with that context and, accordingly, unnaturally strains the regulatory text of the exception in question. Further, the phrase "routine maintenance, repair, and replacement" is itself entirely consistent with the meaning which emerges from a contextual reading. Indeed, even without benefit of context, the use of the word "routine" puts the reader on notice that irregular or unusual activities may not qualify. Although TVA asserts that the exception cannot be read to require anything more than proof that a like project has occurred somewhere in the industry in order for such an

The privilege log refers to a log produced by EPA Enforcement to TVA during this reconsideration process containing a list of documents that EPA Enforcement has withheld on the grounds of privilege.

⁵⁴ See also United States v. City of Menominee, 727 F.Supp. 1110, 1122 (W.D. Mich. 1989) (Defendant is disingenuous to assert that it assumed "all was well," when defendant is a sophisticated corporate player, represented by experienced counsel, heavily involved in activities that are pervasively regulated. Under these circumstances, the defendant should have inquired as to which permit governed its activities.).

activity to be considered "routine," the notion that in determining what is routine one should include as an important consideration the significance of the activity in the life of the unit at issue or other comparable units in the industry does not, in our view, add unascertainable gloss to the regulation's text.

TVA points to the language in the preamble to the 1992 amendments to the NSR rule referencing the need to evaluate "whether a given type of equipment has been repaired or replaced by sources within the relevant industrial category," see 57 Fed. Reg. 32,314, 32,325 (1992), and to a similar reference in the NSPS regulations⁵⁵ to support its conclusion that the regulation has a singular focus, that being whether the activity has been undertaken somewhere else within an industry. As we have already discussed, we are not persuaded that TVA's restatement of these references represents their only, or more natural, reading. See supra Part III.C.3. Indeed, the 1992 preamble reemphasized that the determination was a case-by-case one. See 57 Fed. Reg. at 32,325 (1992). Moreover, the interpretation that we are embracing accepts as an essential ingredient the idea that determining routineness must consider the industrial context of the activity at issue. But it also goes on to look at the four factors — nature and extent, purpose, frequency, and cost — in light of the industry in which the activity occurs.

We are likewise not persuaded that the mere fact that EPA's privilege log includes deliberative documents that may discuss the routine maintenance exception indicates that the interpretation that we are following was not ascertainable to TVA. Whether or not there are ongoing deliberations regarding how to implement this aspect of the New Source Review Program says ultimately very little about what was ascertainable to TVA.

At bottom, it is difficult for us to see how TVA can credibly argue that it could not have foreseen that projects of the magnitude of those at issue here might be determined to be nonroutine. Indeed, as early as 1984, a TVA official stated, "If modifications proposed are extensive enough to be considered reconstruction EPA might try to apply the new source performance standards." See EPA Enforcement Ex. 139, at 8922750. There was, in our view, ample notice to TVA that it was engaged in conduct that would be questionable, when examined under the four factor, case-by-case inquiry referenced in Agency guidance and ultimately adopted as reasonable by the court in WEPCO. Indeed, there is the appearance

Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15." 40 C.F.R. § 60.14(e). As discussed in reference to TVA's prior cite to the NSPS regulations, they are not applicable to the PSD and nonattainment NSR permitting requirements and, thus, are not relevant in this context.

here that, rather than confused, TVA was simply assuming a calculated risk.⁵⁶ As the D.C. Circuit observed in another setting, "[I]t is not unfair to require that one who deliberately goes perilously close to an area of proscribed conduct shall take the risk that he may cross the line." *DiCola v. FDA*, 77 F.3d 504, 508 (D.C. Cir. 1996) (citation omitted).

We also find it striking that TVA is unable to point us to a single instance in which, notwithstanding the magnitude of the projects that it was undertaking, it sought a determination from the relevant regulatory agency regarding the applicability of the routine maintenance exception to these projects.⁵⁷ TVA argues that its failure to do so is irrelevant. In this regard, TVA cites *Hoechst Celanese*, a district court decision from South Carolina, as supporting TVA's argument that it was under no compunction to seek clarification from the Agency. However, a close reading of the district court's decision reveals that the case does not stand for the

⁵⁶ It may well be that TVA's choice to assume the risk was influenced by the fact that, historically, EPA had not pressed the point through enforcement actions. See TVA Response to Initial Brief at 27, 38. But EPA's alleged lack of enforcement is immaterial to TVA's claim that it did not have notice of the regulation's import since the regulatory provision on its face should have provided TVA with appropriate notice. Moreover, it does not explain TVA's choice never to seek a determination from the Agency concerning any of its projects. See discussion in Part III.C.4.a.

Although TVA does not raise an estoppel argument with regard to EPA's alleged lack of enforcement, it is worth noting that such arguments typically fail as a matter of course since a lack of enforcement generally does not rise to the level of "affirmative misconduct" by the government. See In re B.J. Carney Indus., 7 E.A.D. 171, 197 (EAB 1997) ("the Region's conduct [of a five-year delay initiating its enforcement action] did not rise to the level of 'affirmative misconduct' necessary to meet the heavy burden of estopping the government, and hence it must fail."), 192 F.3d 917 (9th Cir. 1999), vacated as moot, 200 F.3d 1222 (9th Cir. 2000); In re Newell Recycling Co., 8 E.A.D. 598, 631 (EAB 1999) (Region's commencement of enforcement action after a period of inaction did not give rise to an estoppel against the government). Similarly, laches, which TVA does raise in its Answer but has not argued in its briefs, is not an affirmative defense that in general can be raised successfully against the government. See Nevada v. United States, 463 U.S. 110, 141 ("the Government is not in the position of a private litigant or a private party"); FDIC v. Husey, 22 F.3d 1472, 1490 (10th Cir. 1994) (the general rule is that the United States is not subject to the defense of laches); Bostwick Irrigation Dist. v. United States, 900 F.2d 1285, 1291 (8th Cir. 1990) ("[W]e have recognized the long-standing rule that laches does not apply in actions brought by the United States.").

⁵⁷ It is commonplace for sources regulated under the CAA to seek applicability determinations in circumstances of uncertainty. The regulations provide for such determinations, *see* 40 C.F.R. § 60.5; 57 Fed. Reg. 32,314 (1992), and EPA has encouraged their use. 57 Fed. Reg. at 32,332 (1992) ("The EPA anticipated, however, that questions will arise regarding certain aspects of this proposal. Because some instances involve discrete judgments, utilities may wish to obtain determinations of applicability. The EPA will provide such determinations upon request * * *."). Indeed, *WEPCO* emerged from a 1988 EPA applicability determination. *See WEPCO*, 893 F.2d 901; *see also* Cyprus Casa Grande Corp. Supplemental PSD Applicability Determination (1987). We note that, apart from the absence of a TVA-specific determination, TVA has not pointed us to any other EPA applicability determination sufficiently on point to bring meaningful support to TVA's argument that its activities fall safely within the ambit of "routine."

proposition that the failure to inquire is irrelevant to a fair notice inquiry. In *Hoechst Celanese*, the defendant in an EPA enforcement action had, in fact, sought prior clarification from a state agency with delegated authority from EPA and had acted in reliance on the state's interpretation. The court merely found that because the company made an inquiry to the state agency, further inquiry to U.S. EPA was not required. *United States v. Hoechst Celanese Corp.*, 964 F. Supp. 967, 982 (D. S.C. 1996), rev'd on other grounds, 128 F.3d 216 (4th Cir. 1997), cert. denied, 524 U.S. 952 (1998).

The absence of an inquiry by TVA is, in our view, a relevant consideration in determining the availability of a fair notice defense in a case like this where the regulation's text and context put TVA on notice that significant projects might well be determined not to be routine maintenance, repair, and replacement. See Fluor Constructors, Inc. v. OSHA, 861 F.2d 936, 942 (6th Cir. 1988) ("If in doubt as to the nature of the lifeline requirement Fluor should have taken the safer position and installed separate lifelines, * * * or at least inquired of OSHA * * *."); Texas Eastern Prod. Pipeline Co. v. OSHA, 827 F.2d 46 (7th Cir. 1987) ("The regulations, while not models of clarity, should not have been incomprehensively vague to Texas Eastern. Texas Eastern made no inquiry.").

In sum, we find that TVA did have fair notice of the interpretation of the regulatory exception for routine maintenance, repair, and replacement that we are following in this case. We find that the interpretation was "ascertainably certain" from both the regulation's text and its context. Moreover, given the magnitude and circumstances of the projects at issue here, TVA reasonably should have been on notice that these projects may not qualify for the routine maintenance, repair, and replacement exception. To the extent that, notwithstanding this ascertainable certainty, TVA was unsure of its regulatory obligations pertaining to the projects, it should have sought clarification from the Agency. Failing to do so, it cannot credibly argue surprise as a result of the Agency's actions.

b. New Rulemaking

TVA makes the related argument that interpretation of the exception that we are following is a new interpretation and, therefore, requires notice-and-comment rulemaking before it can be applied. TVA Post-Hearing Brief at 44. To do otherwise, TVA maintains, would be manifestly unfair because TVA has relied on EPA's prior interpretation in undertaking past projects at its plants.

The starting point in addressing TVA's argument is to determine whether EPA did, in fact, change its interpretation. We conclude that the evidence in the record of this case does not support TVA's contention that EPA has changed its interpretation. Accordingly, we do not reach the legal question whether EPA was required to initiate notice-and-comment rulemaking to effectuate an interpretive change.

TVA has cited to a number of documents that it argues show that EPA once had a different interpretation of the regulation. These documents include a 1986 article entitled, "Extended Lifetimes for Coal Fired-Power Plants: Effect Upon Air Quality," written by two EPA staff employees; a General Accounting Office's ("GAO") 1990 Study on Electricity Supply; a draft 1990 report prepared for EPA by a contractor entitled, "Comparison of the Economic Impacts of the Acid Rain Provisions of the Senate Bill (S.1630) and the House Bill (S.1630) (sic)"; a 1989 letter from ICF Resources Inc., an EPA contractor, responding to an inquiry by the Edison Electric Institute; a 1994 draft document prepared by EPA for circulation to stakeholders for comment; and a portion of a transcript from a May 2000 American Bar Association ("ABA") panel discussion. *See TVA Response to Initial Brief atts. O-P, T-U; TVA Post-Hearing Brief att. F.

We note at the outset two important weaknesses pertaining to the statements cited by TVA. First, with the possible exception of the 1994 draft notice, none of these statements can be taken as authoritative statements by the Agency. The GAO Report, for example, is unclear as to the source of the commentary that it references. The other statements are by Agency staff and contractors having no colorable authority to offer the Agency's official view on the subject.⁵⁹ Thus, for example, the article written by EPA employees explicitly states that the views expressed in the article are the personal views of the authors and do not represent the opinions of EPA.

The second weakness is that, of the documents cited, only the 1994 draft document to stakeholders explicitly addresses the routine maintenance, repair, and replacement exception, and we have questions concerning its relevance in this regard. The draft document that was circulated to stakeholders included draft regulatory text which allegedly would have written into the regulation specific criteria for determining what constitutes "routine" under the NSR regulations. See TVA Post-Hearing Brief att. F. As TVA notes, after "industry participants objected to the suggested definition, * * * EPA did not include the 1994 draft in its 1996 proposed NSR rule." TVA Post-Hearing Brief at 44. In TVA's view, this reveals that EPA was advancing a new interpretation of the regulations but failed to promulgate it. We think this reads too much into EPA's action. The fact that EPA may have been considering regulatory changes to make the definition of

⁵⁸ The 1994 draft document appears to be an EPA draft regulatory provision regarding the interpretation of the routine maintenance exception under NSR. The document was apparently circulated among EPA stakeholders for comment.

⁵⁹ With regard to the portion of the May 2000 ABA panel discussion, we are unswayed by the material provided to the Board. The discussion is not provided in full, and therefore, the context of the discussion cannot be determined, nor can we determine precisely to what the speaker is referring. Further, the informal discussion of a mid-level EPA employee cannot speak for the Agency. *See Paralyzed Veterans v. D.C. Arena*, 117 F.3d 579, 587 (D.C. Cir. 1997), *cert. denied*, 523 U.S. 1003 (1998).

routine maintenance more explicit does not mean that it was changing its interpretation. It is equally plausible that the changes were confirmatory in nature, restating with greater particularity the Agency's preexisting interpretation.⁶⁰

By implication, TVA argues that the Agency's prior view was the one espoused by TVA in this case. We have difficulty finding that any of the cited statements provides support for TVA's view that the Agency's analysis of routineness is limited to assessing whether a given project has been undertaken before somewhere else in the industry.

In sum, based on the limited references that TVA has cited, we are unprepared to find that EPA had earlier espoused an interpretation contrary to the one that we are following here.

D. The Statutory Emissions Increase Requirement as Generally Applied in the PSD Programs (State and Federal)

Having determined that a "physical change" was made at each of the four-teen coal-fired power units at TVA's nine electrical generating plants, we turn now to the second part of the statutory two-part test under the definition of "modification." It requires a demonstration that the physical change resulted in an increase in emissions of a regulated pollutant. In particular, the statutory definition, with emphasis on the emissions increase requirement, is as follows:

The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

CAA § 111(a)(4), 42 U.S.C. § 7411(a)(4) (emphasis added). The regulations for the different programs (NSPS, SIPs, federal PSD, and federal nonattainment NSR) interpret and elaborate on this general statutory emissions increase requirement with detailed provisions.

We note at the outset that the regulations promulgated by EPA implementing the emissions increase test are different for NSPS and NSR. EPA succinctly described this difference in the preamble to NSR rule amendments promulgated in 1992:

⁶⁰ Notably, TVA's suggestion that it was because of industry opposition that the Agency did not proceed with its more-specific definition of the routine maintenance exception is also open to question. In explaining its decision to drop the initiative, EPA explained that this was because "[w]ith other changes being made to NSR applicability, this issue becomes less important." EPA Enforcement Reply Brief, att. E (Letter from Mary D. Nichols, Assistant Administrator for Air and Radiation, U.S. EPA, to William H. Lewis, Morgan, Lewis and Bockius (May 31, 1995)).

In the first step, which is largely the same for NSPS and NSR, the reviewing authority determines whether a physical or operational change will occur. If so, the reviewing authority proceeds in the second step to determine whether the physical or operational change will result in an emissions increase over baseline levels. In this second step, the applicable rules branch apart, reflecting the fundamental distinction between the technology-based provisions of NSPS and the air quality-based provisions of NSR.

57 Fed. Reg. 32,314, 32,316 (1992) (footnote omitted); see also WEPCO, 893 F.2d at 913 (noting that "each program [NSPS and PSD] measures emissions in a fundamentally distinct manner").

In this part of our decision, with one exception, we review the NSR regulatory requirements (both the federal program and the applicable state SIPs) regarding the emissions increase test and apply those requirements to the specific projects and pollutants which EPA Enforcement alleges in its Post-Hearing Brief are at issue in this case.⁶¹ We will also address TVA's argument that the statute requires application of the NSPS emissions increase test as part of all PSD and nonattainment NSR programs. One alleged NSR violation that will not be considered in this Part III.D is the SO₂ violation for Colbert Unit 5, which is governed by the Alabama nonattainment NSR program as it existed prior to amendment in 1983. The emission increase test under the pre-1983 Alabama nonattainment NSR program is similar to the federal NSPS emissions increase test and, therefore, will be discussed in Part III.E below along with the alleged NSPS violations at Colbert Unit 5.⁶²

1. Identification of the TVA Units and the Applicable State and Federal Regulations Discussed in This Part

As noted above, the violations alleged in this case occurred between 1982 and 1996 at fourteen generating units located at nine coal-fired power plants in the states of Alabama, Kentucky, and Tennessee. At various times and for different pollutants, these three states had EPA-approved SIPs and were the applicable permitting authorities. In addition, at some points in time for some pollutants, the applicable permitting program was the federal PSD program. This array of different permitting programs, however, has not resulted in substantially different permitting requirements. To the contrary, the state SIPs generally adopted regulatory language modeled after the language of the federal programs for the pollutants at

⁶¹ See supra Part III.A (identifying claims that were abandoned by EPA Enforcement in its Post-Hearing Brief and identifying the pollutants at each unit that remain at issue).

⁶² The NSPS regulatory requirements for the emissions increase test will be discussed below in Part III.E as well.

issue in this case. Accordingly, the regulatory requirements pertaining to emissions increases are generally the same and thus can be discussed generically in this part of our decision. The following is a brief identification of the power plant units, pollutants emitted by those units, and citations to the applicable regulations that will be discussed in this Part III.D.

As directed by the Board in its May 15 Order, the parties have entered into a comprehensive stipulation regarding both the attainment or nonattainment status of the areas of TVA's plants and the applicable state SIP provisions and federal regulations. *See* Regulation Stipulation. The parties have also attached copies of the applicable SIP provisions and federal regulations to the Regulation Stipulation, set forth in numbered tabs from 1 to 23. The units and the regulations that applied to them during the relevant time frames are as follows:

- a. Federal PSD Units. Paradise Units 1, 2, and 3 were in an area classified as attainment for NO₂. Regulation Stipulation ¶ 3, at 6. During the relevant time, Kentucky did not have an approved SIP governing PSD permitting. Id. at 3, ¶¶ 4-5. Accordingly, the question as to whether TVA was required to obtain a preconstruction permit for NO_X for the physical changes to Paradise Units 1, 2 and 3 is governed by the federal PSD regulations.
- b. Kentucky PSD Units. Shawnee Unit 1 and 4 were in an area classified as attainment for NO₂ and SO₂. Id. ¶ 4, at 6. At the relevant time, ⁶³ Kentucky had an approved SIP for PSD. Id. ¶ 5, at 3-4. Accordingly, the question of whether TVA was required to obtain a preconstruction permit for these pollutants at these units is governed by the applicable Kentucky SIP provisions on PSD identified in the Regulation Stipulation ¶ 5, at 3-4.
- c. Tennessee PSD Regulations (Pre-1994). John Sevier Unit 3, Kingston Unit 6, Kingston Unit 8, and Bull Run Unit 1 were in a location classified during the relevant time as attainment for NO₂, SO₂, and TSP/PM₁₀. Regulation Stipulation ¶ 2, at 6. Tennessee had an approved SIP governing PSD permitting. Id. ¶ 2, at 2. Accordingly, the question as to whether TVA was required to obtain a preconstruction permit for these pollutants at these units is governed by the applicable Tennessee SIP provisions on PSD identified in the Regulation Stipulation ¶ 2., at 2.

 $^{^{63}}$ Construction of the physical changes to Shawnee Unit 1 was commenced on October 31, 1989. EPA Enforcement Ex. 134. The Kentucky SIP provisions governing PSD permitting became effective on October 2, 1989. Regulation Stipulation at 3 \P 5.

- d. Tennessee PSD Regulations (Post-1994). Cumberland Units 1 and 2 were in an area classified as attainment for NO₂, SO₂, and TSP/PM₁₀. Id. ¶ 2, at 6. Tennessee had an approved SIP governing PSD permitting during this time. Id. ¶ 3,at 3. Accordingly, the question as to whether TVA was required to obtain a preconstruction permit for these pollutants at these units is governed by the applicable Tennessee SIP provisions on PSD identified in the Regulation Stipulation at 3 ¶ 3.
- e. Tennessee SIP, Memphis-Shelby County. Allen Unit 3 was located in an area classified as attainment for NO₂, SO₂, and PM₁₀ during the relevant time. Id. ¶ 1, at 5-6. The Allen plant is within the jurisdiction of the Memphis/Shelby County portion of the Tennessee SIP. Id. ¶ 1, at 2. Accordingly, the question as to whether TVA was required to obtain a preconstruction permit for these pollutants at this unit is governed by the applicable Tennessee SIP provisions on PSD identified in the Regulation Stipulation ¶ 1, at 2.
- f. Alabama PSD Regulations (Pre-1987). Colbert Unit 5 was located in an area classified as attainment for NO₂ and TSP/PM₁₀.⁶⁴ Id. ¶ 5, at 6. At this time, Alabama had an approved SIP for PSD. Id. ¶ 6, at 4. Accordingly, the question as to whether TVA was required to obtain a preconstruction permit for these pollutants at this unit is governed by the applicable Alabama SIP provisions on PSD identified in the Regulation Stipulation ¶ 6, at 4.⁶⁵

⁶⁴ As noted earlier, the alleged violation with respect to SO₂ emissions of the nonattainment NSR permitting requirements for Colbert Unit 5 will be discussed below in Part III.E.

⁶⁵ TVA argues that Colbert Unit 5 is exempt from the permitting requirements for NO_x and TSP under the PSD requirements of the state SIP on the grounds that construction of the physical changes was commenced within 18 months of August 7, 1980, and TVA had all of the federal, state and local preconstruction permits necessary under the SIP before that date. TVA Post-Hearing Brief at 56-60. This contention must fail. The exception upon which TVA relies is only applicable if TVA had all required preconstruction permits. ADEM Reg. 16.4.8(d)(5)(i)(ii) (Regulation Stipulation tab 14). As we conclude below in Part III.E, TVA was required to obtain a preconstruction nonattainment NSR permit for SO₂ emissions, which TVA failed to obtain. Accordingly, TVA did not have all required preconstruction permits as of August 7, 1980, or as of any other time. Moreover, TVA has not shown by record evidence that "on-site construction" commenced within 18 months of August 7, 1980. See, e.g., Memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management, U.S. EPA, to U.S. EPA Regional Administrators at 1 (Dec. 18, 1975) (memorandum regarding interpretation of "Commencement of Construction"). Further, TVA has not demonstrated that the contracts to which it refers, as proof of construction commencement, were for "continuous on-site construction" commencing as of an identifiable date. See, e.g., Memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management, U.S. EPA, to U.S. EPA Regional Administrators at 1 (Apr. 21, 1976) (memorandum regarding interpretation of "Commencement of Construction").

g. Alabama PSD Regulations (Post-1987). Widows Creek Unit 5 was in an area classified as attainment for NO₂ and TSP/PM₁₀. Id. ¶ 5, at 6. Alabama had an approved SIP for PSD permitting during the relevant time. Id. ¶ 7, at 5. Accordingly, the question as to whether TVA was required to obtain a preconstruction permit for these pollutants at this unit is governed by the applicable Alabama SIP provisions on PSD identified in the Regulation Stipulation ¶ 7, at 5.

Next, we begin our analysis of the parties' arguments regarding the emissions increase test applicable to the federal and state PSD and nonattainment NSR permitting programs by reviewing the applicable regulatory texts.

2. Regulatory Emissions Increase Test: the "Actual-to-Potential" Test

Throughout this discussion, because the state SIPs generally follow the federal NSR programs,⁶⁶ we will focus primarily on the federal PSD program requirements and identify in the citations or footnotes the parallel requirements under the state SIPs. For the federal PSD program, our discussion will be based upon the 1984 version of the Code of Federal Regulations. The parties have stipulated that the 1984 version of the Code of Federal Regulations contains the text applicable to the violations at Paradise Units 1, 2, and 3 with respect to NO_x emissions. These regulations are not directly applicable to any of the other violations, which are governed instead by the provisions of the state SIPs.

The federal PSD regulatory definition of "major modification" states that, to be included within the definition, a physical or operational change at the source must "result in a significant *net emissions increase.*" 40 C.F.R. § 52.21(b)(2)(i) (emphasis added).⁶⁷ The phrase "net emissions increase" is separately defined in the regulations to require consideration of both "any increase in *actual emissions* from a particular physical change or change in method of operation" and any other "creditable" increases or decreases in actual emissions at the source within a "contemporaneous" period. *Id.* § 52.21(b)(3) (emphasis added).⁶⁸ The issues in the present case concern the first part of this definition (actual emissions from the physi-

⁶⁶ As noted previously, the Alabama SIP's emissions increase test for the nonattainment NSR program prior to its amendment in 1983 was similar to the federal NSPS emissions increase test, not the federal PSD test. These pre-1983 nonattainment NSR provisions are only applicable to SO₂ emissions at Colbert Unit 5, which will be discussed in Part III.E below along with the alleged NSPS violations at Colbert Unit 5.

⁶⁷ Regulation Stipulation tab 1, § 16-77 (S1200-3-9-.01(4)) (Tennessee, Memphis/Shelby County); id. tab 2 (1200-3-9-.01(4)) (Tennessee); id. tab 14, § 16.4.2 (Alabama); id. tab 15, § 16.3.2 (Alabama).

⁶⁸ For state SIP provisions, see *supra* notes 25, 67.

cal change) and, thus, we need not discuss further the second part (creditable contemporaneous increases or decreases elsewhere at the source).⁶⁹

The phrase "actual emissions" as used in the definition of "net emissions increase" is further defined in section 52.21(b)(21).⁷⁰ Generally, the definition of "actual emissions" requires calculation of the actual emissions prior to the physical or operational change, commonly known as the "baseline," which then is compared to the projected⁷¹ emissions after the change. As explained more fully below, the regulations contemplate that the calculation of the pre-change emissions will be based upon data regarding the actual emissions during a two-year period prior to the change that is "representative" of normal operations. In contrast, with respect to the post-change emissions, EPA Enforcement has argued that, under certain circumstances, the post-change emissions are calculated based upon the changed unit's potential to emit.

During the time of the alleged violations in this case,⁷² the definition of "actual emissions" stated in relevant part as follows:

- (i) Actual emissions means the actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with paragraphs (b)(21)(ii)-(iv) of this section.
- (ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operations * * *.

* * * * * * *

⁶⁹ TVA has argued that if it is required to submit permit applications for these projects, it should not be precluded from proposing increases or decreases elsewhere at the source. TVA Post-Hearing Brief at 108-10. These arguments will be considered below in Part III.G, where we address the Compliance Order's requests for relief.

⁷⁰ For state SIP provisions, see *supra* notes 25, 67.

TVA argues that the post-change emissions should be calculated based on actual post-change operating data, rather than a projection of post-change emissions based on the information available to TVA at the time. This argument will be considered below in Part III.D.5.

The definition of "actual emissions" was amended in 1992 to, among other things, add an additional concept of "representative actual annual emissions." 57 Fed. Reg. 32,314 (1992). These amendments, however, are not directly applicable in this case as they were not incorporated by the relevant states into their SIPs at the time when TVA commenced construction of its projects.

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

40 C.F.R. § 52.21(b)(21)(i), (ii), (iv) (1984).⁷³ Under this definition, the prechange "baseline" actual emissions are determined by the emission unit's recent operating history, as specified in subsection (ii). In this case, for the baseline calculation, the parties dispute whether the proper period is the two-year period immediately prior to the physical change or the two-year period with the highest emissions within the five years immediately prior to the modifications. These arguments will be discussed below in Part III.D.3.

With respect to the post-change "actual emissions," EPA Enforcement contends that the Agency consistently interpreted this pre-1992 definition to require a unit affected by a physical or operational change to be subject to subsection (iv). EPA Enforcement states that since the calculation would be performed before the unit had "begun normal operations" following the change, the unit's post-change "actual emissions" are presumed to be equivalent to the unit's "potential to emit." See 45 Fed. Reg. 52,676, 52,677 (1980) ("[T]he source owner must quantify the amount of the proposed emission increase. This amount will generally be the potential to emit of the new or modified unit."). This method of calculating the emissions increase by comparing actual emissions prior to the change with post-change potential emissions is commonly referred to as the "actual-to-potential" test.

TVA argues, on the other hand, that we should apply the reasoning of the Seventh Circuit in the *WEPCO* case and bar the use of post-change "potential" emissions. Instead, according to TVA, we should require use of post-change "actual" emissions in calculating whether the change resulted in an emissions increase. The parties' arguments on this issue will be discussed below in Parts III.D.4 and D.5.

In addition, TVA argues that the manner in which Congress enacted the PSD program in 1977 evinces an intention to incorporate a statutory requirement that any emissions increase be determined based upon whether the change resulted in an increase in the maximum hourly rate of emissions. Because this argument is presented as an issue arising under the statute, which TVA alleges must be applied independent of the regulatorily prescribed test, we will discuss this issue first.

Before turning to the parties' arguments, one additional aspect of the regulations must be noted. As noted above, the parties' arguments focus on the phrase

⁷³ For state SIP provisions, see *supra* notes 25, 67.

"net emissions increase" and the subsidiary definitions that must be considered to understand its meaning. This phrase, as it is used in the definition of "major modification," is qualified by the word "significant." 40 C.F.R. § 52.21(b)(2) (referring to a "significant net emissions increase"). The term "significant" is separately defined in section 52.21(b)(23) as generally meaning 40 tpy of NO_x, 40 tpy of SO₂, and 25 tpy of PM. Thus, for PSD and nonattainment NSR purposes generally, ⁷⁴ any predicted emissions increase must exceed these amounts in order for the permitting requirements to be triggered.

3. TVA's Argument That the Statute Requires EPA to Demonstrate an Hourly Emissions Increase

TVA argues that when Congress amended the CAA in 1977, it intended EPA's long-standing regulatory interpretation of the statutory definition of "modification" in the NSPS context to be applied to the newly created PSD program. TVA thus contends that EPA's regulatory interpretation developed for the NSPS program was, in effect, incorporated into the statutory requirements of the PSD program. TVA devotes considerable discussion in its briefs developing this issue, and we now consider those arguments.

TVA first notes that the definition of "modification" set forth in CAA § 111(a)(4) was originally enacted in 1970, and that EPA's initial regulations promulgated under this definition for the purposes of the NSPS program required measurement of emissions increases in terms of the unit's "emissions rate." TVA also observes that, in the mid-1970s, when EPA first proposed to create a PSD program by regulation (prior to the mandate for such a program in the 1977 CAA amendments), EPA also proposed that an emissions increase be measured based on the unit's "emissions rate." See TVA Response to Initial Brief at 57 & nn.44-45, (citing 39 Fed. Reg. 36,946 (1974); 39 Fed. Reg. 42,514 (1974)). It argues further that emissions rate means the unit's maximum hourly emissions rate. TVA Reply Brief at 32. Accordingly, TVA claims that when Congress amended the CAA in 1977 to create the statutory PSD and nonattainment NSR programs, it legislated in a context where EPA had uniformly interpreted the emissions increase requirement of the term "modification" to be measured based on the unit's maximum hourly rate of emissions.

In particular, TVA states that in 1977, when Congress amended the CAA:

Congress incorporated into its definition of "construction" for purposes of the new NSR program the term "modification," as that term was defined under CAA § 111, and as that term had been consistently interpreted by EPA in contemporaneous interpretations announced be-

⁷⁴ For state SIP provisions, see *supra* notes 25, 67.

tween 1971 and 1977 under the NSPS and NSR rules. Specifically, following initial enactment, in which the NSR provisions had been made to apply *only* to newly-constructed sources, a technical amendment [later in 1977] was made to the NSR program provisions, in which Congress said that the term "construction' when used in connection with any source or facility *includes the modification (as defined in section 7411(a)* of this title) of any source or facility."

The legislative history of the technical amendment explains that the change was made in order to "[i]mplement[] [the] conference agreement to cover 'modification' as well as 'construction' by defining 'construction' in part C to conform to usage in other parts of the Act."

Id. at 58 (citations and footnote omitted) (quoting CAA § 169(2)(C), 42 U.S.C. § 7479(2)(C) (emphasis added by TVA); 123 Cong. Rec. H11957 (daily ed. Nov. 1, 1977) (emphasis and alterations added by TVA)). Based upon this background, TVA concludes, "[I]t is clear that Congress intended that only a NSPS modification at an existing unit is 'construction' activity that can subject an existing unit to potential NSR permitting as a result of a 'physical or operational' change." Id. at 60.75

In essence, TVA argues that the statutory definition for the PSD program of "construction," CAA § 169(2)(C), 42 U.S.C. § 7479(2)(C), which references "modification" as defined in CAA section 111, contains within it a requirement that there must be an increase in the maximum hourly emissions rate of the unit. Carried to its logical conclusion, this argument suggests that any NSR regulation promulgated by EPA which ignored this maximum hourly emissions rate would be incompatible with the statute. As explained below, we reject this argument as nothing other than an untimely challenge to EPA's 1980 PSD regulations, which plainly established an emissions test based upon the unit's actual emissions (expressed as an average rate measured in tons per year) during the period prior to the physical or operational change and without reference to whether there was also an increase in the maximum hourly emissions rate.

As noted above, the federal regulations provide that a permit is required if the physical change results in a "significant net emissions increase." 40 C.F.R. § 52.21(b)(2)(i).⁷⁶ "Net emissions increase" in turn is defined as an increase in "actual emissions," *id.* § 52.21(b)(3), and that term is defined as "equal to the *average rate, in tons per year*, at which the unit actually emitted pollutants during a two-year period which precedes" the physical change. *Id.*

TVA reasserts this same argument in its post-hearing briefs. See TVA Post-Hearing Brief at 29, 31-33.

⁷⁶ For state SIP provisions, see *supra* notes 25, 67.

§ 52.21(b)(21)(ii) (emphasis added).⁷⁷ Briefly stated, the PSD regulations require consideration of the actual amount, measured in tons per year and expressed as an average annual rate, of pollution emitted by the source prior to the change and to be emitted after the change, whereas the NSPS maximum hourly emissions rate test looks to the maximum rate at which the source can emit on an hourly basis. These differences and the shift in focus from potential hourly emissions rate to actual emissions, in tons per year, was thoroughly explained in the preamble to the rulemaking by which the PSD test was promulgated. *See* 45 Fed. Reg. 52,676, 52,700 (1980).

By arguing that the NSPS hourly emissions rate test must be applied as an initial step in the PSD or nonattainment NSR permitting context, TVA in effect challenges the emissions test required by the Agency's duly promulgated regulations. However, we have frequently stated that we will not generally entertain challenges to the Agency's regulations in the context of an enforcement or permit proceeding. See In re B.J. Carney Indus., 7 E.A.D. 171, (EAB 1997) (enforcement proceeding), 192 F.3d 917 (9th Cir. 1999), vacated as moot, 200 F.3d 1222 (9th Cir. 2000); In re Echevarria, 5 E.A.D. 626, 634 (EAB 1994) (enforcement proceeding); In re Puna Geothermal Venture, 9 E.A.D. 243, 249 n.7 (EAB 2000) (challenges to regulations not entertained in a permitting proceeding); In re City of Port St. Joe, 7 E.A.D. 275, (EAB 1997) (same); In re Suckla Farms, Inc., 4 E.A.D. 686, 698 (EAB 1993) (same); In re Ford Motor Co., 3 E.A.D. 677, 682 n.2 (Adm'r 1991) (same). We see no compelling reason to depart from this principle here. Accordingly, TVA's arguments are rejected as untimely challenges to the Agency's PSD regulations (and the EPA-approved SIPs).

We also reject TVA's argument because a plain reading of the statutory text makes clear that the CAA is not limited in the manner argued by TVA. Indeed, there is no suggestion in the language of the statute itself that an emissions increase must be measured as "maximum hourly emissions rate." The statutory text merely refers to "increase[] [in] the amount of any air pollutant emitted." CAA § 111(a)(4), 42 U.S.C. § 7411(a)(4) (emphasis added). It does not specify how an increase is to be measured (whether by maximum hourly rate as suggested by TVA or by tons per year as stated in the PSD and nonattainment NSR regulations or by any other method), or even use the words "hourly" or "emission rate." Cf. 40 C.F.R. § 52.21(b)(21)(ii). Had Congress intended to restrict the Agency's discretion in this respect, it surely would have stated this limitation expressly in language far more limiting than the provision it chose to enact into law.⁷⁸

⁷⁷ For state SIP provisions, see *supra* notes 25, 67.

⁷⁸ EPA Enforcement has suggested that, under the statutory definition, emissions could be measured by any of the following: "the unit's actual emissions, its maximum theoretical potential to emit, its present (that is, considering deterioration) potential to emit, its permitted allowable emissions, or any other measure." EPA Enforcement Post-Hearing Brief at 133.

TVA has cited no case, Agency interpretation, or other authority published in the nearly twenty-five years since the enactment of the 1977 CAA amendments for its novel argument that the statutory definition must be interpreted for both the NSR and NSPS programs to require measurement of emissions as a "maximum hourly emissions rate." To the contrary, there are numerous instances in which EPA and the courts have stated that the emissions increase test is different for the two programs. See, e.g., WEPCO, 893 F.2d at 905, 913;79 Puerto Rican Cement Co. v. EPA, 889 F.2d 292, 298 (1st Cir. 1989); Letter to Timothy J. Method, Assistant Commissioner, Indiana Department of Environmental Management, from David Kee, EPA Director of Air and Radiation Division at 2-4 (Jan. 30, 1990); see also Alabama Power, 636 F.2d 323, 397-98 (D.C. Cir. 1980) (holding that, even though the same statutory definition of the term "source" in CAA § 111 applies to the NSPS program and the PSD programs, EPA may define the "component terms" used within section 111's definition differently because of differences in the purposes and structure of the two programs).

Moreover, we see nothing in the statutory text, legislative history, or the circumstances of the 1977 amendments cited by TVA that would compel us to interpret the statutory definition more narrowly than the court applied in *WEPCO*. In that case, the court specifically observed that "each program [NSPS and PSD] measures emissions in a fundamentally distinct manner." *WEPCO*, 893 F.2d at 913. We certainly see no requirement that measurement of an emissions increase may only be based on "maximum hourly emissions rate."

EPA has chosen, through its regulations, to advance the technology centered purposes of the NSPS for steam generating boilers by measuring emissions increase based on maximum hourly emissions rate, and to advance the locality centered purposes of the PSD and nonattainment NSR programs by measuring emissions based on tons per year. *Compare* 40 C.F.R. § 60.14, *with* 40 C.F.R. §§ 51.24(b)(4), 52.21(b)(4); *see also Northern Plains Resource Council v. EPA*, 645 F.2d 1349, 1356 (9th Cir. 1981).80 As noted above, the propriety of

⁷⁹ In discussing the statutory emissions increase requirement, the Seventh Circuit stated that arguments regarding "emission rates" arise under the regulations, not under the statute itself. *WEPCO*, 893 F.2d at 910. The court then held as follows: "For purposes of the statutory requirement, we simply observe that the rejuvenated Port Washington plant will *produce more emissions* after the completion of the renovation project than the operating deteriorated plant produced shortly before the project was undertaken." *Id.* (emphasis added). In so holding, the court noted that WEPCO had admitted that the "replacement program" would enable its "deteriorated generators to operate at full capacity," which would cause emissions to "increase from their current operating levels." *Id.*

No TVA argues that EPA acknowledged the existence of an hourly emissions rate requirement by excluding "an increase in the hours of operation or in the production rate" from "physical change or change in the method of operation." See 40 C.F.R. § 52.21(b)(iii)(f). This argument, however, has no merit — it is not only incompatible with a plain reading of the "hours of operation" exception, but it Continued

that regulatory choice, made more than twenty years ago, may not be reviewed in this case and, in particular, we see no reason to interpret the statutory definition of "modification" as compelling the use of "maximum hourly emissions rate" as a predicate to both programs.

Thus, we reject TVA's argument that Congress' cross-reference in the PSD portion of the CAA to the definition of "modification" in the NSPS portion of the statute ensconced the NSPS regulatory emissions increase test as a fixed and immutable emissions test applicable to the PSD or other NSR programs. Next, we turn to the parties' arguments arising under the terms of the regulations themselves, beginning with the arguments regarding calculation of the pre-change "baseline" emissions.

4. Base-line Emissions Issues

As noted earlier, the regulatory definition of "actual emissions" which is used in the definition of "net emissions increase" contemplates the comparison of the average emissions, in tons per year, during a pre-change "baseline" period to the emissions after the change. In this part of our discussion, we will consider the parties' arguments regarding the proper method for calculating the emissions in the baseline period. For ease of reference, the applicable regulatory text is as follows:

In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operations * * *.

40 C.F.R. § 52.21(b)(21)(ii).81

(continued)

also has been rejected by the EPA and by two federal circuit courts. In particular, the Seventh Circuit stated as follows:

Despite WEPCO's protestations, we note initially that the EPA's refusal to apply the "production rate/hours of operation" exclusion was proper. This exclusion — which states that "[a] physical change or change in the method of operation shall not include * * * [a]n increase in the hours of operation or in the production rate," — was provided to allow facilities to take advantage of fluctuating market conditions, not construction or modification activity.

WEPCO, 893 F.2d at 916 n.11 (quoting 40 C.F.R. § 52.21(b)(iii)(f)) (modifications made by the court) (citations omitted); see also Puerto Rican Cement Co. v. EPA, 889 F.2d 292, 298 (1st Cir. 1989). In sum, the Agency for many years has interpreted the hours of operation/production rate exception as applicable to operational changes where there is no other change such as the physical changes made by TVA at issue in this case.

⁸¹ For state SIP provisions, see *supra* notes 25, 67.

EPA Enforcement argues that the baseline emissions must be based upon the two-year period that immediately precedes the particular physical change. EPA Enforcement Post-Hearing Brief at 117-21. EPA Enforcement contends that the regulation quoted above establishes a presumption that the two-year period immediately before the physical change is representative of normal operations. *Id.* at 117-18. It argues that this presumption is explained in an Agency guidance document. *See id.* at 118 (citing *New Source Review Workshop Manual* at A.39 (draft Oct. 1990));82 EPA Enforcement Reply Brief at 26. EPA Enforcement concludes that, if TVA believes that the immediately preceding two-year period is not representative, "TVA must persuade the Board that any alternative period is more representative of unit emissions." EPA Enforcement Post-Hearing Brief at 117.

Although the parties extensively argue whether a rebuttable presumption exists in favor of one baseline period over another, we conclude that any such rebuttable presumption would have no effect on our ruling here, as TVA's evidence is sufficient to overcome any such presumption.

EPA Enforcement's witness, Mr. Van Gieson, testified, based on a review of certain data regarding these units, including the monthly operating statistics reports, that "there is nothing to suggest that the two year time period before the [project] did not represent normal source operations." EPA Enforcement Ex. 277, at 31 (Van Gieson pre-filed testimony). As EPA Enforcement argued in its briefs, given the steady deterioration of the units involved, and the associated progressive decline in unit performance, it was reasonable, absent other information, to look at the period immediately prior to the change as indicative of the unit's operational capacity at the time of the change. EPA Enforcement Reply Brief at 26. Thus, although Mr. Van Gieson's testimony does not eliminate the possibility that another time period might be more representative, it provides some evidence that the two-year period immediately preceding the physical changes at issue is "representative" in this case, and, even if EPA Enforcement were not entitled to the benefit of a presumption, it nevertheless produced sufficient evidence to establish a prima facie case regarding its proposed baseline period. In any case, TVA's evidence is sufficient to rebut this evidence and any suggested presumption.

The New Source Review Workshop Manual was issued as a guidance document for use in conjunction with new source review workshops and training, and to guide permitting officials with respect to PSD requirements and policy. Although it is not accorded the same weight as a binding Agency regulation, the Manual has been looked to by this Board as a statement of the Agency's thinking on certain PSD issues. See, e.g., In re Steel Dynamics, Inc., 9 E.A.D. 165, 173 n.8 (EAB 2000); In re Hawaii Elec. Light Co., 8 E.A.D. 66, 72 n.7 (EAB 1994); In re Masonite Corp., 5 E.A.D. 551, 558 n.8 (EAB 1994). As noted by EPA Enforcement, the New Source Review Workshop Manual provides guidance that the two years immediately prior to the change is presumed to be the representative period. In contrast, the preamble to the 1992 amendments to the NSR regulations suggests that any two-year period within the previous five years may be representative. 57 Fed. Reg. 32,314 (1992). We need not decide which of these two presumptions controls at the time of the various projects at issue in this case, as TVA's evidence is sufficient to overcome any such presumption, as discussed in the text.

TVA introduced evidence to establish that, at least for some of the units,⁸³ another two-year period was more representative of normal source operations. TVA's witness, Mr. Houston, testified that "the 24-month period having the highest annual emissions rate during the five years preceding the project [is] the baseline period representative of normal operations." TVA Ex. 9 at 5 (Houston prefiled testimony).

Mr. Houston testified that he used the "high two-of-five" period as representative of normal operations because it would take into account "any fluctuations in utilization of the unit that may be due to various factors, such as weather, availability of other units on the system, etc." *Id.* Mr. Houston further testified that it is TVA's goal to operate its coal-fired generators to achieve full capacity. *Id.* at 4; Tr. at 950. He also testified that he chose the high emissions period as the representative period because "generally the closer the operation is to normal is going to mean the emissions are going to be higher with more operations." Tr. at 950. In its post-hearing brief, TVA explains the import of Mr. Houston's testimony as follows:

In other words, by using the high 2 of 5 period as the baseline period, which varies from unit to unit depending upon the particular conditions of the unit during the 5-year period before the change, one would avoid the likelihood that factors wholly independent from the project or the conditions of the unit before the project — such as weather and availability of other units on the system, i.e. independent demand factors — would affect the operation of the unit during the baseline period.

TVA Post-Hearing Brief at 73-74.

In its post-hearing brief, EPA Enforcement attempts to discredit Mr. Houston's testimony by noting that "Mr. Houston ignores the fact that these units were deteriorating at a steady rate, so that although TVA would have preferred to run the units at a higher capacity, normal operations of the unit did not reach those levels." EPA Enforcement Post-Hearing Brief at 26. While EPA Enforcement's observation that these units were generally deteriorating is established by the record in this case, ⁸⁴ EPA Enforcement did not introduce any evidence to establish, for example, that for those units with emissions in the two-year period immediately preceding the physical changes that were lower than the emissions in the

For several of the units, TVA's evidence established that the appropriate baseline period is the two-year period immediately preceding the physical changes at issue. *See* TVA Ex. 9, atts. 10 (Allen Unit 3), 12 (Cumberland Unit 1).

⁸⁴ See App. A.

high-two-of-five period, such lower emissions were more likely the result of deterioration as opposed to other factors such as weather conditions.

TVA has fairly put in question whether the reduced emissions in the two years before the project were not caused by general deterioration, but rather were due to other factors including weather. In sum, TVA introduced evidence explaining why a period other than the first two years prior to the physical changes would be more representative of normal operations and EPA Enforcement has not sufficiently rebutted that evidence, having only introduced testimony that Mr. Van Gieson concluded, based on a review of certain data, that there was "nothing to suggest that the two year time period before the [project] did not represent normal source operations." EPA Enforcement Ex. 277 at 31 (Van Gieson pre-filed testimony).

Given EPA Enforcement's inability to adduce evidence sufficient to overcome TVA's rebuttal evidence, we conclude, based on the evidence in the record of this case, that the two-year period having the highest emissions in the five-year period preceding the change is the most representative of normal source operations and shall be used as the baseline period for calculation of the pre-change emissions of the fourteen units at issue in this case. Although we rely on Mr. Houston's testimony in concluding that this period is most representative in this case, in our following discussion we will generally refer to Mr. Van Gieson's testimony and emission calculations as his testimony includes coverage of the emissions in this period and provides a clearer comparative framework. Mr. Houston did not provide testimony as to the post-change emissions calculation that, as discussed below, we find appropriate. Although there are some differences between the twenty-four month periods that Mr. Van Gieson and Mr. Houston concluded were the high-two-of-five for specific projects, such differences are not material. In addition, we note that both Mr. Van Gieson and Mr. Houston determined that the high-two-of-five period for some of the projects was, in fact, the two-year period immediately preceding the physical change.

Next, we turn to the issues regarding calculation of emissions attributable to the post-change period.

5. Issues Regarding Post-Change Emissions: WEPCO Decision and Other Issues

As noted above, the Agency historically has interpreted the definition of "actual emissions" as requiring post-change emissions for a unit that has been subject to a physical or operational change to be measured as the unit's potential to emit. In particular, the Agency has generally interpreted changed units as subject to subpart (iv) of the definition of "actual emissions." For ease of reference, that subpart states as follows:

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

40 C.F.R. § 52.21(b)(21)(iv) (1989).85 This subpart has been viewed as applicable to changed units under the notion that, when the preconstruction prediction of emissions is made, the unit to be affected by the change has not "begun normal operations" as a changed unit. As noted earlier in this decision, the method of calculating emissions increase based on these regulations as advocated by EPA Enforcement is referred to as the "actual-to-potential" test.

TVA argues in the present case that the actual-to-potential test for calculating whether an emissions increase will result from a physical change should not be applied to the changes made to the fourteen units at issue here. TVA first argues that, in *WEPCO*, the Seventh Circuit rejected application of the actual-to-potential test for replacement projects allegedly similar to those at issue in this case. *See* TVA Post-Hearing Brief at 63-66; *WEPCO*,893 F.2d 901 (7th Cir. 1990). Second, TVA argues that it is inappropriate in a case, such as this one, arising years after the physical changes were completed, for the post-change emissions to be calculated based on a hypothetical projection of emissions (which we will refer to as a "retrospective prediction" method), when the post-change emissions can be calculated based on evidence of the post-change operations (we will refer to such a test based on operating data as a "actual-to-confirmed-actual" test). TVA Post-Hearing Brief at 66-71. These issues are discussed below.

a. The Actual-to-Potential Test: WEPCO and the Region's Allegations in the Compliance Order

As noted, TVA argues that we should adopt the analysis used by the Seventh Circuit in *WEPCO*, 893 F.2d 901 (7th Cir. 1990), and reject EPA Enforcement's analysis based on the actual-to-potential test. In the *WEPCO* case, the Seventh Circuit did not uphold the Agency's application of the actual-to-potential test to what the court referred to as proposed "like-kind replacements" at a facility that had an extensive history of prior operations. Instead, noting that it had concerns regarding the "assumption of continuous operations" for a unit that had a prior operating history, the Court stated that "the EPA's reliance on an assumed continuous operation as a basis for finding an emissions increase is not properly supported." *Id.* at 918.

The projects at issue in WEPCO involved substantial renovations of five 80-MW coal-fired generating units at WEPCO's Port Washington electric power plant. All five of the units had experienced significant age-related deterioration

⁸⁵ For state SIP provisions, see *supra* notes 25 & 67.

that prevented them from being operated at their original capacity. *Id.* at 905-06. Indeed, one of the units, Unit 5, had been shut down completely due to the possibility of catastrophic failure if it were operated. *Id.* WEPCO's proposed renovation project would have enabled all five units "capable of generating at [their] designed capability until year 2010." *Id.* at 906.

When the court turned to its review of the Agency's determination that the proposed renovation projects would result in a "significant net emissions increase" under the PSD regulations, the court noted that "[i]n calculating the plant's post-renovation potential to emit, the EPA bases its figures on round-the-clock operations (24 hours per day, 365 days per year) because WEPCO could potentially operate its facility continuously, despite the fact that WEPCO has never done so in the past." *Id.* at 916. With this background, the court noted that it was "troubled by the EPA's assumption of continuous operations." It also stated, however, that "EPA cannot reasonably rely on a utilities' own unenforceable estimates of its annual emissions." *Id.* at 917. Nevertheless, it concluded that "we find no support in the regulations for the EPA's decision to wholly disregard past operating conditions at the plant." *Id.* It therefore held that "the EPA's reliance on an assumed continuous operation as a basis for finding an emissions increase is not properly supported." *Id.* at 918.

In the present case, TVA argues that use of the actual-to-potential test was "expressly repudiated by the Seventh Circuit in *WEPCO*," TVA Post-Hearing Reply Brief at 38, and that the *WEPCO* holding must be followed by the Board. *Id.* at 38 n.38. In contrast, EPA Enforcement argues that we should apply an actual-to-potential test in this case. EPA Enforcement Post-Hearing Brief at 73-90, 116-61; EPA Enforcement Initial Brief at 34-49. With respect to the Seventh Circuit's WEPCO decision, EPA Enforcement contends that (1) *WEPCO* is distinguishable from this case in that TVA intended the projects at issue in this case to restore lost generating capacity, which TVA intended to use (EPA Enforcement Post-Hearing Brief at 143-44, 152), (2) the Seventh Circuit's reasoning is faulty in several respects (*id.* at 147-48), and (3) by its 1992 rulemaking, known as the "WEPCO Rule," EPA formally determined, through notice and comment rulemaking, the circumstances in which an "electric utility steam generating unit" may use a test other than the actual-to-potential test for determining the post-change emissions of the changed unit. *Id.* at 146-47, 150-52.

While the parties have devoted considerable time in their briefs arguing the applicability of the Seventh Circuit's analysis to this case, we conclude that it is unnecessary for us to decide these issues. In the present case, notwithstanding EPA Enforcement's advocacy of the appropriateness of an actual-to-potential test in the context of this reconsideration, we decline to apply that test because of the way that the Region, in the exercise of its enforcement discretion, framed the test in its Compliance Order. In particular, the Compliance Order, as amended on April 10, 2000, states that "[i]n determining whether a significant emissions in-

crease has resulted from a major modification in the case of electric utilities, actual pre-modification emissions are compared with *projected actual* emissions after the modification." Compliance Order ¶ 18 (citing *WEPCO*, 893 F.2d 901 (7th Cir. 1990)) (emphasis added). This statement is part of the Region's notice to TVA of the rules and regulations that it is accused of having violated and, as such, provided TVA with notice of the Region's theory of its case. While EPA Enforcement's briefing of the actual-to-potential test can be viewed as, in effect, a request for us to disregard the Region's statement in the Compliance Order of its view of the applicable emissions test, nevertheless, we are disinclined to hold TVA to a more rigorous⁸⁶ standard than was alleged in the Compliance Order.⁸⁷ Accordingly, we reject EPA Enforcement's proposed use in this case⁸⁸ of the actual-to-potential method of calculating the alleged emissions increase.⁸⁹

b. After-the-Fact "Projection" of Emissions vs. Evidence of Post-Change Emissions

EPA Enforcement apparently anticipated the possibility that it might be precluded from using the actual-to-potential test in that it introduced evidence of the alleged emissions increases based on what we will refer to generally as a retrospective prediction or, when discussing the particular methodology used by Mr. Van Gieson, as an actual-to-projected-actual test. See EPA Enforcement Exs. 175-88; EPA Enforcement Post-Hearing Brief at 153-62. EPA Enforcement's proposed projection of post-change emissions are based upon what it believes "should have been put into a NSR permit application had TVA applied for a permit" prior to making the particular physical changes at issue. EPA Enforcement Post-Hearing Brief at 156. To make its "projections," EPA Enforcement used "relevant information" that was available to TVA and shows either TVA's own "specific numeric predictions of a unit's operations after the project" or "information

⁸⁶ The actual-to-potential test is a more rigorous standard in this case than the other proposed methods of calculating the post-change emissions increase because EPA Enforcement's evidence uniformly established higher emissions under the actual-to-potential method than under the other proposed methods. *See* EPA Enforcement Exs. 175-88.

⁸⁷ Although this statement in the Compliance Order may not be a legal bar to application of a different test, we do not believe under the circumstances of this case that EPA Enforcement should on reconsideration be permitted to alter a foundational premise of the order that we are reconsidering, and change such a fundamental component of its theory of the case in a way that inures to its benefit.

TVA's arguments that it did not have "fair notice" of the alleged applicability of the actual-to-potential method, see TVA Post-Hearing Brief at 99-107, are most because we have rejected application of the actual-to-potential method in this case. Further, TVA has not argued that it lacked fair notice of emissions increases calculated based upon a projection of post-change emissions (nor could it, because a preconstruction permit application must, at a minimum, contain such projections).

⁸⁹ We express no view as to whether the actual-to-potential test would or would not be appropriate in other cases.

about component performance and loss in generating ability of the unit due to the component's failures." *Id.* at 157.

In contrast, TVA argues that it is inappropriate in a case such as this one, arising years after the physical changes were completed, to calculate post-change emissions based on a hypothetical projection of emissions, when the post-change emissions can be discerned from evidence of the post-change operations that in fact occurred. TVA Post-Hearing Brief at 66-71. (We will refer to TVA's proposed test based on post-change operating data as an "actual-to-confirmed-actual" test.) TVA articulates this argument as follows:

EPA Enforcement's reasoning has no place in an enforcement action, where EPA Enforcement is alleging a violation of NSR requirements after the fact. In an enforcement action, such as this case, EPA Enforcement has actual data of pre-project as well as post-project emissions. It simply makes no sense for EPA Enforcement to "project" a unit's actual emissions after the project (based on an unrealistic set of assumptions) in calculating "[a]ny increase in actual emissions from a particular" physical or operational change (40 C.F.R. § 52.21(b)(3)(i)), when EPA Enforcement has actual emissions data for both the pre-project and post-project periods. See Tr. at 519. Certainly, projections based upon assumptions cannot be considered best evidence.

TVA Post-Hearing Brief at 65 (emphasis added by TVA).

TVA's argument that this proceeding should look to historical post-change operating data, rather than hypothetical projections, must be rejected as contrary to the requirements of the CAA and applicable NSR regulations. Initially, it is worth noting that the only authority TVA cites for its argument is one part of the regulations that interprets and elaborates upon the statutory definition of "modification." TVA Post-Hearing Brief at 65 (citing 40 C.F.R. § 52.21(b)(3)(i)).90 We conclude that these regulatory terms and phrases cannot be read in isolation, but must be interpreted and applied in light of the statutory and regulatory architecture and, in particular, in the context of the violations alleged in the Compliance Order.

The particular regulatory text cited by TVA was promulgated to elaborate upon the emissions increase requirement of the statutory definition of "modification." The regulatory text cited by TVA appears at 40 C.F.R. § 52.21(b)(3)(i), which is the definition of "net emissions increase." The term "actual," as used in this context, was intended to signal a departure from reliance on "potential emission rate" and has no bearing upon the choice in an enforcement context as to whether post-change emissions are to be calculated based upon either a hypothetical projection of post-change emissions or data regarding the post-change operations. See 45 Fed. Reg. at 52,700.

First, we note that the Compliance Order was issued pursuant to CAA § 113, 42 U.S.C. § 7413, which authorizes the Administrator to issue orders directing compliance with the CAA, 91 as well as CAA § 167, 42 U.S.C. § 7477, which directs the Administrator to take such measures as necessary "to prevent construction or modification" of a nonconforming facility. Because the Act specifically contemplates that an enforcement action to prevent construction may be brought before modification of a facility is complete, Congress must have intended the determination in such an enforcement action to be based upon projections of emissions increases. 92

Moreover, the preconstruction permitting requirements also contemplate that the source owner must decide whether to apply for a permit based upon predictions of whether the emissions increase from a physical change will exceed the applicable significance levels after the change has been made. The applicable significance level for NO_x and SO₂ is 40 tpy; for PM it is 25 tpy.⁹³ As demonstrated below, a violation of the requirement to obtain a preconstruction permit brought after the physical change has been completed must also be determined based on the same standards as would apply in either the permitting context or the enforcement context where construction has not been completed — namely a prediction of emissions based on the information known before the physical change is made.⁹⁴ Our analysis follows.

The statute expressly contemplates that projections of the impact of a change must be made before construction. Before a permit is issued, among other things, the owner or operator of the source must, using projections of post-change emissions, demonstrate that emissions from the modified source will not violate air quality requirements. Specifically, section 165 states that "[n]o major emitting facility * * * may be constructed unless a permit has been issued for such proposed facility." CAA § 165, 42 U.S.C. § 7475 (emphasis added). Further, the owner or operator must demonstrate that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" the NAAQS, among other things. CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3). A per-

⁹¹ More specifically, the Compliance Order alleges that TVA violated the CAA's requirement that it obtain NSR permits before beginning "construction." Compliance Order ¶¶ 57, 67, 82 (citing CAA § 165, 42 U.S.C. § 7475, 40 C.F.R. § 52.21(b)(2)).

⁹² In an enforcement action brought prior to completion of construction, the con-sequences of the physical change (that is being constructed) can only be determined by predictions.

⁹³ See definition of "significant" at 40 C.F.R. § 52.21(b)(23) (1984).

⁹⁴ In particular, the violation at issue (failure to obtain a preconstruction permit) is determined based in part upon whether the change (that requires a permit) results in an emissions increase. CAA § 111(a)(4), 42 U.S.C. § 7411(a)(4); 40 C.F.R. § 52.21(b)(2)(i) (1984) (major modification means any "physical change * * * that would result in a significant net emissions increase") (emphasis added).

mit may not be issued unless "there has been an analysis of any air quality impacts projected for the area as a result of growth associated with such facility." CAA § 165(a)(6), 42 U.S.C. § 7475(a)(6).

Moreover, if a permit is issued containing operating or other restrictions based upon the results of these predictions, the permit restrictions cannot be removed even when the post-change operations demonstrate that the predictions were erroneous. *Hawaiian Elec. Co. v. EPA*, 723 F.2d 1440, 1446 (9th Cir. 1984) ("Nothing in the Clean Air Act or its legislative history indicates that Congress intended that EPA should have to reconsider each and every PSD permit if modeling predictions were subsequently drawn into question.").

This statutory and regulatory structure has two important features relevant to the present discussion: (1) the permit must be obtained *before* the physical change is made, and (2) whether a physical change requires a permit is determined in part by reference to anticipated results or consequences, which necessarily would occur *after* the physical change is made. Thus, the only way for the owner or operator of the source to know whether a permit is required for any particular physical change is for the owner or operator to make a prediction as to whether the emissions increase will occur. This observation was described by EPA in the 1992 preamble to amendments to the NSR regulations as follows:

Applicability of the CAA's NSR provisions must be determined in advance of construction and is pollutant specific. In cases involving existing sources, this requires a pollutant-by-pollutant projection of the emissions increases, if any, that will result from the physical or operational change.

57 Fed. Reg. 32,314, 32,316 n.8 (1992).

Because the statute and regulations contemplate that the regulated entity must predict future events in order to determine whether a permit is required, we conclude that it is appropriate to base a finding of violation (for failure to obtain the permit) upon what the entity reasonably could have predicted prior to beginning "construction." Any other construction of the statute would turn the preconstruction permitting program on its head and would allow sources to construct without a permit while they wait to see if it would be proven that emissions would

⁹⁵ While the parties have not identified any case law relevant to this issue (which TVA describes as a question of the validity of "retrospective projection") and we are not aware of any in the preconstruction permitting context, it is nevertheless instructive that "retrospective projections" are commonly utilized for determining a party's liabilities in other contexts. *See, e.g., Coleman v. Commissioner*, 53 T.C.M. (CCH) 598 (1987) (determination of tax liability based on "retrospective prediction" of residual value in order to determine whether transaction was properly characterized as lease or sale).

increase. Clearly Congress did not intend such an outcome, which would eviscerate the *preconstruction* dimension of the program.

Thus, we find that the question of whether the physical changes made by TVA required a preconstruction permit must be determined based upon evidence regarding projections of emissions increases that should have been performed by TVA before it made the physical changes. However, as we note in the following section (where we will consider EPA Enforcement's evidence regarding its proposed actual-to-projected-actual test and TVA's challenges to that evidence), the confirmed-actual data may be considered for the limited purpose of either confirming or refuting the *reasonableness* of a particular prediction methodology and for other purposes.

c. EPA Enforcement's Proof of Emissions Projections and TVA's "Causation" Argument (Demand Growth and Related Issues)

EPA Enforcement relies primarily on the testimony of Mr. Van Gieson to establish that, prior to the fourteen physical changes made by TVA to nine of its coal-fired units, TVA should have determined that those changes would result in "significant net emissions increases," thereby triggering the PSD and nonattainment NSR permitting requirements. Specifically, EPA Enforcement states as follows:

These calculations, performed by EPA's expert witness, Mr. Van Gieson, identify the future emissions from the unit that would result from the physical change being completed if a reasonable prediction of net emissions increase had been performed before the change.

EPA Enforcement Post-Hearing Brief at 156. In essence, in the part of his analysis at issue here, Mr. Van Gieson looked back retrospectively to make a prediction, based on information available to TVA prior to the projects, as to what the emissions increases would likely be. This type of calculation we will generally refer to, in our following discussion, as a "retrospective prediction" and the specific analysis performed by Mr. Van Gieson we will refer to as his actual-to-projected-actual method.

In order to predict retrospectively the emissions increase resulting from the physical changes, Mr. Van Gieson referred to two sources of information regarding unit performance: "TVA's own internal documents justifying the construction," which provided an analysis of how some of the units would operate differently after the change, and information about component performance and loss in generating ability due to component failure reported by TVA to the North American Electric Reliability Council's ("NERC") Generating Availability Data System ("GADS"). *Id.* The GADS records contain information submitted by electric

power utility owners and operators, including TVA, regarding instances in which a unit is shut down due to problems with specific parts, or components, of the boiler (called a "forced outage") or where the unit has a reduced operating capacity due to such problems (called a unit "derating"). The GADS records contain information regarding which part of the boiler caused an outage or derating, the start and end time and date, the duration in hours, and the megawatt hour ("MWH") loss of the outage or derating.

For each of the fourteen units at issue in this case, Mr. Van Gieson reviewed the GADS information for the high-two-of-five baseline period⁹⁶ and identified the MWH loss attributable to outages and deratings associated with the part of the boiler being altered in the project at the unit. Mr. Van Gieson then "calculated the emissions effect that would occur after the part of the boiler was repaired or replaced and the megawatt hours lost were reduced to zero." *Id.* at 158. Mr. Van Gieson's calculations of the resulting increased emissions are set forth in EPA Enforcement's Exhibits 175-88, identified by the heading "projected Net Representative Future Actual Emissions Increase," and further identified by reference to the high-two-of-five baseline.⁹⁷ Mr. Van Gieson's conclusions as to the emissions increase for each unit and each pollutant as to which EPA Enforcement seeks a finding of violation (which we previously identified in Part III.A above)⁹⁸ are summarized as follows:

Chart No. 4

	NO _x (tpy)	SO ₂ (tpy)	PM (tpy)
Allen Unit 3	113	266	
Bull Run Unit 1	760	1,608	14
Colbert Unit 5	2,697	10,739	60

⁹⁶ See supra Part III.D.3, discussing our conclusion that the appropriate baseline period, based on the record of this case, is the two-year period with the highest emissions within the five-years immediately prior to the modifications, not the two years immediately preceding the physical changes at issue in this case. Mr. Van Gieson also reviewed the same information for the two-year period immediately preceding the physical change to each unit.

⁹⁷ EPA Enforcement's Exhibits 175-88 set forth Mr. Van Gieson's emissions calculations under several different methods, including the actual-to-potential method and calculations of emissions based on post-change operating data, as well as the method discussed in the text (for both the high-two-of-five baseline and the two-year baseline immediately preceding the physical changes).

⁹⁸ As noted in Part III.A, EPA Enforcement abandoned allegations as to violations with respect to some of the pollutants at certain units.

Cumberland Unit 1	452		_99
Cumberland Unit 2	277		4
John Sevier Unit 3	35	98	
Kingston Unit 6	228	782	
Kingston Unit 8	318	737	4
Paradise Unit 1	883		
Paradise Unit 2	2,359		
Paradise Unit 3	2,323		
Shawnee Unit 1	148	177	
Shawnee Unit 4	263	309	
Widows Creek Unit 5	37	51	2

EPA Enforcement Exs. 175-88. Mr. Van Gieson testified that these retrospective predictions of emissions increases "recreate emissions calculations that would have been prepared by TVA at the time of the modification with information that was available at that time." EPA Enforcement Ex. 277 at 3 (Van Gieson pre-filed testimony). EPA Enforcement argues further that "TVA's own internal documents generated at the time of each physical change prove that the physical change was intended to increase operations and, consequently, would result in an emissions increase." EPA Enforcement Post-Hearing Reply Brief at 27-28.

EPA Enforcement's requests for findings of violation (*see supra* Part III.A, Chart No. 1) were initially based upon its arguments that the actual-to-potential test is the appropriate method for determining whether a permit was required for the changes. Because we have held for the reasons stated in Part III.D.5.b above that EPA Enforcement may not rely upon the actual-to-potential test in this case, EPA Enforcement's evidence does not support its requests in several respects. In particular, Mr. Van Gieson's calculations for his actual-to-projected-actual method, with the high-two-of-five baseline, do not show that the significance level¹⁰⁰ (of 40 tpy for SO₂ and NO_x, and 25 tpy for PM) would be exceeded for the following units and pollutants: (1) Bull Run Unit 1 for PM; (2) Cumberland Unit 1 for PM; (3) Cumberland Unit 2 for PM; (4) John Sevier Unit 3 for NO_x; (5) Kingston Unit 8 for PM; and (6) Widows Creek Unit 5 for both NO_x and PM. Accordingly, before turning to any of TVA's objections and challenges to Mr. Van Gieson's testimony, we hold that EPA Enforcement has failed to prove that

⁹⁹ Mr. Van Gieson's calculations showed a decrease in emissions for this pollutant at this unit.

¹⁰⁰ See definition of "significant" at 40 C.F.R. § 52.21(b)(23) (1984).

TVA was required to obtain a PSD or nonattainment NSR permit for these pollutants at these units.

TVA raises two primary arguments to discredit Mr. Van Gieson's testimony. First, TVA argues that Mr. Van Gieson's own testimony as to his calculation under another methodology based upon the post-change operating data (which shows decreased emissions in some instances) demonstrates that Mr. Van Gieson must have used erroneous assumptions in making his projections. TVA Post-Hearing Brief at 67-68. Second, TVA argues that Mr. Van Gieson misused the data contained in the GADS records. *Id.* at 68-70; *see also* TVA Post-Hearing Reply Brief at 49-51. More specifically, TVA states that "GADS data overestimate the impact of outages and forced deratings, offer no insight into future operations of a unit as a whole, and bear no relationship to demand or causation." TVA Post-Hearing Reply Brief at 53; *see also id.* at 53-55, 57-61. These arguments must be rejected for the following reasons.

For two reasons, we reject TVA's arguments that Mr. Van Gieson's testimony regarding the post-change operating data demonstrates that he must have used erroneous assumptions. By this argument, TVA juxtaposes data regarding post-change operations — in other words, actual-to-confirmed-actual evidence¹⁰¹ — which in a minority of instances showed reduced pollutant emissions in the first two-years of post-change operations,¹⁰² with Mr. Van Gieson's retrospective predictions to argue that Mr. Van Gieson must have made a mistake. In evaluating TVA's argument, it is first important to note that Mr. Van Gieson's testimony regarding the confirmed-actual evidence only relates to the first two-year period following the changes and, therefore, cannot be looked to as definitive proof that the project did not result in an emissions increase. To the contrary, because we are looking at changes from a baseline of the two-year period with the highest emissions within the previous five years, the fact that an occasional decline in emissions was observed in the confirmed-actual evidence is not remarka-

¹⁰¹ Both Mr. Van Gieson and TVA's witness, Mr. Houston, provided an analysis of the available information regarding TVA's post-change operation of the units. These analyses were not "retrospective predictions," but instead were performed similar to the calculation of emissions in the baseline period. We generally refer to this analysis as an actual-to-confirmed-actual test.

Mr. Van Gieson's calculation of the confirmed-actual emissions demonstrated reduced emissions for the pollutants that remain at issue at the following units: Bull Run Unit 1 for NO_X; John Sevier Unit 3 for SO₂; Kingston Units 6 and 8 for NO_X and SO₂; Shawnee Unit 4 for NO_X and SO₂; and Widows Creek Unit 5 for SO₂. As noted in the text, EPA Enforcement introduced many documents showing that TVA undertook these projects with the intention to increase operations after the changes. The confirmed-actual evidence in the record only shows that TVA had not, within the first two years of post-change operations, increased emissions at these plants above the previous high emissions period. Such evidence is not sufficient to rebut the direct evidence of TVA's intention to increase operations, from which TVA reasonably could have predicted emissions increases. However, as discussed below, we hold that the totality of EPA Enforcement's proof as to a predicted emissions increase at one of these units, Widows Creek Unit 5, for SO₂ is not sufficient.

ble. What is remarkable is the large number of units for which emissions actually increased in the first two-year period immediately following the performance of the change when compared to the previous high pre-change emission period. One would expect that, if the projects did not result in emissions increases, emissions after the physical changes would not generally increase above the amount of emissions during what has been determined to be the previous high pre-change emissions period.

In particular, contrary to TVA's suggestion, Mr. Van Gieson's calculations based upon the first two-years' confirmed-actual data actually confirmed that the following units increased emissions for the following pollutants:¹⁰³

Chart No. 5

	NO _x (tpy)	SO ₂ (tpy)	PM (tpy)
Allen Unit 3	1,732	2,391	
Bull Run Unit 1		4,546	
Colbert Unit 5	1,774	7,467	30
Cumberland Unit 1	21,187		
Cumberland Unit 2	4,192		
John Sevier Unit 3	298		
Paradise Unit 1	1,007		
Paradise Unit 2	421		
Paradise Unit 3	10,674		
Shawnee Unit 1	720	673	

EPA Enforcement Exs. 175-88. Thus, Mr. Van Gieson's review of the confirmed-actual data confirms that significant emission increases in fact occurred in many instances in the first two-years of post-change operations. Indeed, the confirmed-actual evidence shows that there was a significant NO_x emissions increase at John Sevier Unit 3, where Mr. Van Gieson's retrospective predictions did not show that the applicable significance level of 40 tpy would be exceeded.¹⁰⁴

¹⁰³ Increases for pollutants for which EPA Enforcement has not requested a finding of violation are omitted.

¹⁰⁴ EPA Enforcement has not argued in its briefs that, if the retrospective prediction methodology is used, we should nevertheless make a finding of violation based upon the confirmed-actual evidence in this instance.

Second, as we have held above in Part III.D.5.b, violations of the PSD and nonattainment NSR preconstruction permitting requirements should be based upon evidence as to predictions that a source owner reasonably could have made prior to undertaking the particular physical change. This conclusion, as noted, is based upon the statutory and regulatory requirement that NSR permits be obtained before the effects of the project can be known and, therefore, calculation of an emissions increase must be based upon projections. Such retrospective predictions should generally seek to eliminate (to the extent possible) knowledge obtained solely from hindsight¹⁰⁵ in order to most accurately gauge whether a respondent should have obtained a permit prior to undertaking the particular change. Significantly, had TVA properly complied with the preconstruction permitting requirements and submitted predictions of emissions increases, TVA would not have been allowed to later challenge those predictions on the grounds that confirmedactual data demonstrated error in the predictions. Hawaiian Elec. Co. v. EPA, 723 F.2d 1440, 1446 (9th Cir. 1984) ("Nothing in the Clean Air Act or its legislative history indicates that Congress intended that EPA should have to reconsider each and every PSD permit if modeling predictions were subsequently drawn into question."). TVA should not, by its failure to comply with the Act's requirements, obtain an after-the-fact data review that is not available to other permit applicants.

Thus, TVA's mere reference to a minority of instances where the confirmed-actual evidence showed a decrease in emissions, rather than an increase as predicted by Mr. Van Gieson's retrospective predictions, does not, by itself, demonstrate that the reduced emissions would have been predicted by TVA prior to making the physical changes at the unit or that Mr. Van Gieson's prediction methodology is generally unreasonable. In this regard, it is notable that no TVA officer or employee testified (and TVA did not argue in its briefs) that TVA in fact predicted (or even could have predicted) the decreases that apparently occurred. *See*, *e.g.*, EPA Enforcement Exs. 12, 48, 69, 75, 81, 89, 93 (TVA documents stating that no environmental analysis would be performed).

We do not hold that confirmed-actual emissions data for the post-change period can never be used to determine whether a violation of the permitting requirements occurred. Instead, we simply hold that such evidence is not the best evidence of a violation of a requirement that, if properly complied with, required the respondent to make a reasonable prediction prior to undertaking the particular change. The confirmed-actual data may be looked to as indicating, for example,

¹⁰⁵ See Coleman v. Commissioner, 53 T.C.M. (CCH) 598 (1987) (in order to determine whether the transaction was properly characterized as a sale, as opposed to a financing agreement, for tax purposes, the Tax Court rejected the testimony of an expert who admitted difficulty in avoiding "hindsight in making retrospective residual value predictions." Instead, the Tax Court accepted the testimony of an expert who based his retrospective prediction testimony on information available in the market at the time of the transaction, and avoided information regarding subsequent changes in the market affecting whether the purported owner actually retained a residual interest in the property.).

whether the prediction methodology was generally reasonable. Here, as noted above, the confirmed-actual data demonstrates that a significant number of emissions increases were, in fact, observed in the first two years of post-change operations. This observed increase generally demonstrates that Mr. Van Gieson's retrospective predictions were reasonable.

We also reject TVA's argument that Mr. Van Gieson misused the data contained in the GADS records and that this alleged misuse warrants rejection of Mr. Van Gieson's conclusions. As noted above, TVA argues that "GADS data overestimate the impact of outages and forced deratings, offer no insight into future operations of a unit as a whole, and bear no relationship to demand or causation." TVA Post-Hearing Reply Brief at 53; see also id. at 53-55, 57-61. More specifically, TVA contends that the GADS records show when, and to what extent, a unit is "not available" to produce electricity, not the extent to which actual utilization of the unit is reduced as a result of the "derating." TVA Post-Hearing Brief at 69. Based on this contention, TVA suggests that, when a unit is operated before a "derating" at less than maximum capacity, it is logically possible for the unit to experience a "derating" (i.e., a reduction in maximum available capacity) that does not require TVA to curtail the use of the unit. Id. at 69-70 (discussing a hypothetical example presented to TVA's witness). TVA thus contends that the GADS "derating" data "is *independent* of the demand on the unit during that period" and that "[o]ne must also know, at a minimum, whether the unit was called upon to run before and after the project at a level that would have caused the forced temporary derating to have some significance for the unit's actual utilization." Id. TVA asserts further that:

The starting point for any emission projection must be the expected *demand* for the unit, because it is demand that dictates at what level and for how long a unit would be operated during the relevant post-project period. * * * Mr. Van Gieson did not in any way consider actual post-project demand in his "projections," let alone estimate the level of demand that TVA would have projected based on then available information.

TVA Post-Hearing Brief at 71.

There are two principal errors in this argument. First, this argument does not support TVA's conclusion that Mr. Van Gieson's predictions must be rejected. TVA's argument only applies with respect to the "derating" data reported in GADS; TVA does not suggest that the GADS "forced outage" data fails to reflect reduced utilization. As discussed below, "forced outages" are defined by GADS as unplanned interruptions in actual service. Accordingly, the "forced outage" data reflects an impact on actual utilization, not just on available capacity.

Second, contrary to TVA's suggestion, EPA Enforcement did in fact begin by considering TVA's actual intent to utilize the units more after the projects than it was able to use them before the projects. Specifically, Mr. Van Gieson testified that "[f]or calculations done to project the effect of the modifications on emissions of the unit, I relied on both TVA estimates of the effect of the modification and on information from [GADS] * * *." EPA Enforcement Ex. 277, at 4 (Van Gieson pre-filed testimony) (emphasis added). The italicized part of this quotation demonstrates that, as part of his analysis, Mr. Van Gieson referred to TVA's own preproject statements regarding the expected effect of the projects on post-change utilization. Here, Mr. Van Gieson was referring to the cost-benefit analysis TVA made before each project was approved for Allen Unit 3, Cumberland Unit 1,106 and Colbert Unit 5. Id. at 37, 41, 45. The specific TVA documents relied upon by Mr. Van Gieson are EPA Enforcement Exs. 22, 63, and 93,107 which contain specific statements by TVA quantifying the extent to which TVA anticipated increased utilization of the particular units. In addition to Mr. Van Gieson's reference in his analysis to three TVA documents, EPA Enforcement identified many other TVA documents reflecting TVA's intent to increase utilization of its units after completing the projects at issue in this case.

An example of TVA's pre-project estimates, which were relied upon by Mr. Van Gieson, is the "Project Authorization" memorandum for the changes made to Colbert Unit 5, which bears a stamp indicating approval by the TVA Board of Directors in August 1979. EPA Enforcement Ex. 22. In that document, TVA stated that "[t]he proposed work is *intended* to *restore* the unit capability, *reduce* the total outage rate approximately 33 percent," among other things. *Id.* (emphasis added). TVA noted that "[w]hen the unit was operated it was derated 100 MW * *," and that "at least another \$50 million capital cost for new capacity can be saved as a result of the *restored* 100-MW capacity." *Id.* (emphasis added). These statements are direct evidence that, prior to the physical changes at Colbert Unit

¹⁰⁶ TVA also raises additional arguments specific to Mr. Van Gieson's testimony regarding Cumberland Unit 1. TVA Post-Hearing Reply Brief at 52-53.

¹⁰⁷ In TVA's Post-Hearing Brief, TVA argues that Mr. Van Gieson's reliance on EPA Enforcement Ex. 93 as showing a 7 MW derating at Cumberland Unit 1 constitutes error. TVA notes that in that exhibit, which is a copy of a TVA document prepared in 1991, TVA merely predicted a future 7 MW derating. TVA argues that Mr. Van Gieson erred by assuming that the derating actually occurred. TVA states that TVA Ex. 9, att. 14 (GADS data) demonstrates that the 7 MW derating was never realized. The exhibit and attachment to which TVA refers consists of 26 computer discs containing compressed data. TVA has not identified where on those discs we may find the proof to which it refers — it is not our responsibility to search such voluminous information in the absence of some further direction by TVA. However, we conclude that Mr. Van Gieson's calculations based on a 7 MW derating are merely cumulative, as his predicted emissions increase without the increase attributable to the 7 MW derating greatly exceeds the 40 tpy significance level for NO_X. Without the 7 MW derating, Mr. Van Gieson's retrospective prediction calculation showed a 216 tpy NO_X emissions increase. EPA Enforcement Ex. 178. It bears noting that the confirmed-actual evidence showed that NO_X emissions increased by 21,187 tpy. *Id*.

5, TVA intended to increase use of that unit after completing the physical changes. While there is no need to corroborate such direct evidence of TVA's prechange intention, it is nevertheless worth noting that TVA's witness, Mr. Houston, admitted that, for five years prior to the changes at Colbert Unit 5, TVA never operated that unit at higher than 400 MW per hour, and that, during every month during the year after the changes, TVA operated Colbert Unit 5 at 500 MW per hour or higher. Tr. 978-81.

Many other documents introduced into evidence by EPA Enforcement show TVA's expectation that the physical changes would "eliminate forced outages," EPA Enforcement Ex. 57 (Allen Unit 3), or "improve the availability and forced outage rate." EPA Enforcement Ex. 3 (Paradise Unit 1); see also EPA Enforcement Exs. 7 (Paradise Unit 2), 19 (Colbert Unit 5), 11 (Paradise Unit 3), 72 (Bull Run), 102 (Cumberland Unit 2). Other documents include references like the following:

- "excessive boiler tube failure," "improve reliability." EPA Enforcement Exs. 2 (Paradise Unit 1), 9 (Paradise Unit 3), 73 (Bull Run).
- "[t]his cracking has caused an increase in header nipple tube failures and thus a decrease in unit availability." EPA Enforcement Ex. 81 (Cumberland Unit 1).
- "Paradise Unit 1 has reached forced outage levels exceeding 20 percent. Boiler tube leaks in the furnace and cyclones have accounted for 96 percent of all forced outages." EPA Enforcement Ex. 4; see also EPA Enforcement Exs. 10 (Paradise Unit 3), 17 (Paradise Units 1, 2, & 3).
- "Based on samples taken, the existing tubes are failing because of creep damage experienced while operating at high-temperatures. This indicates that these tubes have reached the end of their life." EPA Enforcement Ex. 46 (Widows Creek Unit 5); see also EPA Enforcement Ex. 48 (Widows Creek Unit 5).
- "The secondary superheater has been the number 3 contributor to forced outages at Cumberland in the past 5 years." EPA Enforcement Ex. 87 at 8914159; see also EPA Enforcement Ex. 88 ("has resulted" in damage causing loss of generation).
- "Stub tube wall failures on the secondary superheater outlet headers are contributing 18½ of the boiler forced outage hours for [Cumberland] unit 2." EPA Enforcement Ex. 101 at 8914497.

- For Cumberland Units 1 and 2, "lost generation is averaging over 350,000 MW-hr per year from emergency forced outages for repair of tube leaks in the secondary superheater." EPA Enforcement Ex. 111 at 8935347.
- "Over the last four years there has been experienced an average of fourteen four-day outages to repair the tube leaks in the lower waterwall tubes." EPA Enforcement Ex. 122 (Kingston Unit 6).

These examples of TVA's own statements made in project justification documents prior to the physical changes to the units at issue in this case demonstrate that, by the physical changes, TVA expected to eliminate significant forced outages and other negative effects on actual unit utilization. Thus, based on TVA's own pre-project statements, EPA Enforcement established a reasonable inference that TVA in fact held a pre-project intention to operate all of these units more after the physical changes than it was able to operate them before the changes. In short, we believe that statements such as "eliminate forced outages" indicate an intention to operate a unit more after the physical changes than was possible prior to the change.

This reasonable inference regarding TVA's pre-project intention is confirmed and substantiated by the fact that TVA did, in fact, increase utilization of a majority of the units within the first two years immediately following the physical changes. The confirmed-actual data in this case, which we have held may be looked to as generally demonstrating the reasonableness, or unreasonableness, of a prediction methodology, is also relevant in assessing the reasonableness of a retrospective prediction of emissions increase in another respect. The confirmedactual data showing increased operations, and hence increased emissions, is relevant information regarding the source operator's state of mind or, more specifically, its intention to increase operations after making the physical changes. See, e.g., United States v. Louisiana-Pacific Corp., 682 F.Supp. 1141, 1161-63 (D. Colo. 1988) (holding, for the purposes of determining whether a source violated the PSD preconstruction permitting requirements, that evidence of a source owner's knowing and routine violation of maximum operation restrictions contained in a state operating permit is grounds for disregarding the permit's restrictions when calculating the source's emissions for PSD applicability). Here, EPA Enforcement introduced evidence that both directly and by reasonable inference shows that TVA intended to increase operations of the fourteen units after it completed the physical changes at those units. Mr. Van Gieson's testimony that TVA in fact increased operations and pollutant emissions after the physical changes at many of these units is evidence that corroborates the inference that TVA intended to increase operations and, therefore, should have predicted increased

emissions. 108

The reasonable inference regarding TVA's pre-project intention to increase use of these plants after the physical changes is further substantiated by TVA's own expert witness, who testified, in justifying a high-two-of-five baseline, regarding TVA's intent to "operate[] its boiler units to achieve a full load limit based on design flow." TVA Ex. 9, at 4 (Houston pre-filed testimony). It naturally follows from such an intent that, when the physical changes corrected pipe deterioration that had caused forced outages or prevented operation at full design capacity, TVA intended to increase utilization after the physical changes were made. Thus, we conclude that, before it made the physical changes at issue in this case, TVA intended to increase utilization of the units after the changes, and it should have thus predicted increased emissions from those changes.

We need not determine whether TVA used each unit in the pre-change period to the unit's maximum available capacity. Notwithstanding any lack of absolute physical limitation on increased use of a unit prior to the changes to that unit, TVA's statements of intention, as a justification of the costs of the project, demonstrate TVA's own conclusion that the project would remove a physical constraint on the unit's utilization. Given that the projects were intended to remove these limitations, it is reasonable to conclude that emissions increases resulting from the project should have been predicted by TVA. Moreover, the evidence demonstrates that, in general, changes in annual system-wide demand did not affect the utilization of the coal-fired units. See TVA Ex.12, att. 7. Instead, increased utilization of the coal-fired units in the early to mid-1980s was correlated with TVA's decision to decrease use of its nuclear units; demand-related deployment of the coal-fired units remained relatively constant from 1986 through 1992 (when most of these projects were performed) because, in general, increases in demand after 1985 were accommodated by increased use of TVA's nuclear units. Tr. at 469, lines 6-7; 1059, lines 8-25; 1060, lines 105; TVA Ex. 12, att. 7. Thus, a preponderance of the evidence in the record of this case demonstrates that it was predictable that emissions would increase above the applicable significance levels as a result of the physical changes at issue, and that such increases were not attributable to changes in aggregate demand on TVA's system.

Where Mr. Van Gieson was able to identify a TVA statement that quantified the anticipated increased post-change utilization, Mr. Van Gieson used TVA's own quantification. EPA Enforcement Ex. 277 at 37, 41, 45 (Van Gieson pre-filed testimony). However, where there were only generalized statements

we do not need to decide in this case whether post-change emissions data, standing alone, is sufficient to establish an inference regarding the source operator's pre-change state of mind. As discussed below, EPA Enforcement introduced other evidence from which a reasonable inference of such intention could be drawn. Thus, here, the post-change data merely corroborates this inference.

from TVA of its intent to increase utilization, Mr. Van Gieson turned to the GADS records to quantify the increased utilization associated with the specific boiler components that were being repaired or replaced in each project. Those records include data regarding lost megawatt hours during "forced outages," which are defined by GADS as an outage caused by an event that "requires immediate removal of a unit from service" or delayed removal from service, but which is a type of outage that "can only occur while the unit is in service." TVA Ex. 11, at p. III-6 to -7 (GADS Data Reporting Instructions). Based on the nature of the GADS information, we conclude that it was reasonable for Mr. Van Gieson to turn to the GADS records as providing a means for quantifying the amount of emissions increase resulting from TVA's intended increased utilization of the units after completion of the physical changes. Mr. Van Gieson's use of this data was appropriately focused narrowly on the "lost" megawatt hours associated with the specific components that were replaced as part of the physical changes. Moreover, this approach satisfies the WEPCO court's concern that post-change emissions projections should take into account the prior operating history of the unit. WEPCO, 893 F.2d at 918. Here, the prior operating history is accounted for by the selective use of only the deratings and forced outages associated with the components being replaced.

To the extent that TVA argues that the GADS records do not show whether the unit will be operated more or less after the physical change, *see* TVA Post-Hearing Reply Brief at 53, this argument is addressed and rejected by our conclusion, based on other evidence, that TVA in fact intended to increase utilization after the physical changes. To the extent that TVA is arguing that the GADS data do not necessarily show any forced utilization reduction in the pre-change period, this argument cannot stand in the face of the GADS reporting instructions applicable to "forced outages," which specifically state that such outages are an interruption in service — in other words, an interruption in actual utilization and, therefore, necessarily a pre-change reduced utilization.

Finally, to the extent that TVA argues that the GADS data may still overestimate the amount of any increased emissions, it is worth noting the extent to which Mr. Van Gieson's projections predicted that the applicable significance threshold would be exceeded. In particular, with only one exception (Widows Creek Unit 5, discussed below), the predicted exceedences were more than two times, and up to more than fifty-eight times, the applicable 40 tpy significance level for NO_x and SO₂. Without further proof, we are unprepared to accept a

¹⁰⁹ This means that for all but one unit, TVA would have predicted an exceedence of the 40 tpy NO_X and SO₂ significance level if it intended to increase utilization by as little as one-half of the previous forced shutdown and deratings associated with the components being repaired or replaced. Two units, Allen Unit 3 for NO_X and John Sevier Unit 3 for SO₂, were more than twice, but less than three times the 40 tpy significance level. In addition, Shawnee Unit 1 for NO_X was more than three Continued

margin of error of 100% or more in the GADS data.

Under these circumstances, where we have already found that TVA intended to increase utilization and justified these projects by reference to eliminating already existing forced outages, we conclude that EPA Enforcement has shown, by a preponderance of the evidence, that the projects at the following units would result in "significant net emissions increases" of the identified pollutants. TVA has not suggested that more accurate information was available to it from which it could have more accurately projected the amount of increased utilization that it intended. The units and pollutants for which we find that EPA Enforcement has shown a physical change that would result in a significant net emissions increase are as follows (an "X" indicates a finding of violation):

Chart No. 6

	NO_X	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	
Colbert Unit 5	X	*110	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		
John Sevier Unit 3		X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	
Paradise Unit 1	X		
Paradise Unit 2	X		
Paradise Unit 3	X		
Shawnee Unit 1	X	X	
Shawnee Unit 4	X	X	

times, but less than four times the 40 tpy significance level. All other units and pollutants were predicted to exceed the significance level by more than four times. Indeed, in the more extreme case, TVA would have known that if it increased utilization by any more than 1/58th of the previous forced shutdowns and deratings, the significance level would be exceeded.

⁽continued)

 $^{^{110}}$ As noted above, the alleged violation of the permitting requirements with respect to SO_2 at Colbert Unit 5 will be discussed below in Part III.E.

With respect to Widows Creek Unit 5 for SO₂, for which the projected emissions increase was 51 tpy, or only 11 tpy over the 40 tpy significance level, we hold that, on balance, the evidence is not sufficient to conclude by a preponderance of the evidence that TVA should have anticipated that an exceedence of the significance level would occur. We make this judgment by considering both Mr. Van Gieson's testimony regarding his projected emissions increase of 51 tpy, and Mr. Houston's testimony suggesting that Mr. Van Gieson's reliance on GADS derating information and the full amount of the associated MWH loss may overestimate the expected emissions increase to some degree. As discussed above, we have generally concluded that Mr. Van Gieson's predictions of emissions increases that more than double the 40 tpy significance level are sufficient to establish that TVA should have predicted an exceedence of the significance level for such pollutants. Nonetheless, because Mr. Van Gieson relied principally on the GADS data in arriving at his projection for Widows Creek Unit 5 and the record suggests that there may be some margin of error in the estimates based on GADS data, we conclude that the predicted increase for SO₂ at Widows Creek Unit 5 is not sufficient proof that TVA should have anticipated that the significance level would be exceeded. Therefore, on the record before us, we find no violation of the PSD and nonattainment NSR permitting requirements with respect to Widows Creek Unit 5.

For the foregoing reasons, we find that EPA Enforcement has sustained its burden of proof that twenty pollutants at eight of TVA's coal-fired plants would have increased as a result of physical changes made to thirteen of the units at those plants. In addition, as discussed below in Part III.E we find that the physical changes to Colbert Unit 5 resulted in an emissions increase of SO₂ under the Alabama nonattainment NSR program in effect prior to 1983. Accordingly, we find a total of twenty-one violations of the PSD and nonattainment NSR permitting requirements.

E. NSPS and Alabama Pre-1983 Nonattainment NSR Emissions Increase Requirements

The Compliance Order alleges that the changes made to Paradise Unit 3 in 1984 and the changes made to Colbert Unit 5 in 1982 violated the NSPS requirements. In its post-hearing brief, EPA Enforcement states that it has decided not to pursue its claim that the changes made to Paradise Unit 3 violated the NSPS requirements. EPA Enforcement Post-Hearing Brief at 163 n.102. With respect to Colbert Unit 5, however, EPA Enforcement states:

TVA's rehabilitation project so significantly changed the boiler so that the maximum achievable hourly emission rate increased after the project, triggering the modification provision of the NSPS and making Colbert Unit 5 an "affected unit" subject to 40 C.F.R. § 60, Subpart Da.

Id. at 163. TVA objects, arguing that the work performed at Colbert Unit 5 did not make it subject to NSPS. For the following reasons, we hold that the changes made by TVA to Colbert Unit 5 were "physical changes" that increased the unit's maximum hourly emissions rate and that, therefore, Colbert Unit 5 became subject to the NSPS for electric steam generating boilers as a result of such changes.

In this part of our analysis we also discuss the allegations that the changes to Colbert Unit 5 resulted in an emissions increase under the applicable provisions of the Alabama SIP's pre-1983 nonattainment NSR permitting requirements, which were in effect at the time of the project at Colbert Unit 5.

The NSPS regulations are applicable to the owner or operator of any electric utility steam generating unit, "the construction or *modification* of which is commenced after the date of publication * * * of any standard * * * applicable to that facility." 40 C.F.R. § 60.1(a) (1982) (emphasis added). EPA has published standards applicable to electric utility steam generating units for which construction or modification is commenced after September 18, 1978. 44 Fed. Reg. 33,613 (1979) (codified at 40 C.F.R. pt. 60, subpt. Da §§ 60.40a-49a) (*see* Regulation Stipulation tab 23). These NSPS cover PM, NO_x and SO₂.

For the purposes of part 60, the term "modification" is defined as follows:

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility * * *.

40 C.F.R. § 60.2 (1982). Further,

Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act.

Id. § 60.14(a). Emissions rate is expressed as "kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable." Id. § 60.14(b). Briefly stated, these provisions require that, for purposes of determining the applicability of the NSPS requirements, an emissions increase is calculated based upon the potential hourly emissions of the unit, not its actual emissions. A substantially similar test was required by the Alabama SIP provisions governing nonattainment NSR prior to their amendment in 1983. See Regulation Stipulation tab 16,

§ 16.3.2(b)(4) (referring to increases in "the potential emission rate").¹¹¹ The only difference in the pre-1983 Alabama SIP provisions is that the maximum hourly rate is used to calculate a maximum potential annual emissions rate, which must increase by 100 tons or more. *Id.*

The changes at issue in the present case made to Colbert Unit 5 were commenced in 1982, after publication of the NSPS applicable to electric utility steam generating units. Accordingly, TVA was required to comply with the NSPS for the changes at Colbert Unit 5 if those changes constituted "modifications" within the meaning of the applicable NSPS regulations.

The initial question is whether the changes made by TVA to Colbert Unit 5 fall within the scope of "routine, maintenance, repair, and replacement which the Administrator determines to be routine for a source category * * *," which is **NSPS** regulations governing modifications. exception to the an 40 C.F.R. § 60.14(e)(1) (1984). TVA argues that the project at Colbert Unit 5 falls within this exception. TVA argues that this exception is functionally identical to the exception for routine maintenance, repair and replacement under the PSD and nonattainment NSR programs. Specifically, TVA relies, as support for its claims with respect to NSPS, on the same evidence and arguments that we discussed above in Part III.C of this decision regarding the NSR programs. See TVA's Reply Brief at 61. In addition, TVA asserts that "[t]he differences between the NSPS and NSR routine maintenance, repair and replacement language is a distinction without a difference." Id.

In contrast, EPA Enforcement argues that the NSPS routine maintenance exception requires an affirmative determination by the Administrator that the activity falls within the exception. EPA Enforcement is correct. The regulatory text, on its face, states that the determination must be made by the Administrator: "routine maintenance, repair and replacement which the *Administrator* determines to be routine for a source category * * *." 40 C.F.R. § 60.14(e)(1) (1984). In addition, we note that this exception is different from the exception under the NSR regulations in that the NSPS version makes reference to "routine for the source category," whereas no similar reference appears in the NSR regulations. *Compare id. with* 40 C.F.R. § 52.21(b)(2)(ii). Because TVA has not shown that the Administrator has determined, on a source category basis, that changes of the kind undertaken at Colbert Unit 5 are routine maintenance, repair and replacement, TVA cannot avail itself of this exception to the NSPS.¹¹²

The Alabama SIP provisions define "potential" as the "maximum capacity to emit."

We note as well that the facts of this case do not suggest a basis for reaching a different conclusion under the NSPS regulations from the one we reached under the NSR programs as discussed above. In our earlier discussion in Part III.C, we concluded that the changes made to the Colbert Unit 5

Next, we turn to the question of whether the physical changes made to Colbert Unit 5 resulted in an emissions increase within the meaning of the NSPS regulations and the pre-1983 nonattainment NSR provisions of the Alabama SIP.

EPA Enforcement argues that TVA's thirteen-month extended outage at Colbert Unit 5, which began in 1982 and continued into 1983, was "intended to restore approximately 100 MW of lost capacity." EPA Enforcement Post-Hearing Brief at 165. EPA Enforcement argues that it has demonstrated, through the testimony of Mr. Van Gieson, that the maximum achievable hourly emissions rate at Colbert Unit 5 increased as a result of the physical changes made to that unit. *Id.* at 165-66. EPA Enforcement also argues that this change increased Colbert Unit 5's potential emissions by more than 100 tons per year. *Id.* at 77.

Mr. Van Gieson's conclusion is based upon a substantial increase in the maximum hourly generation rate reported by TVA in its monthly and annual operating reports. Specifically, Mr. Van Gieson reviewed TVA's Monthly Operating Statistics Report for the one-year period before the project and noted that TVA never operated Colbert Unit 5 during that period at an hourly generation rate of more than 387 MW.¹¹³ TVA's witness, Mr. Houston, confirmed that, for five years prior to the project, Colbert Unit 5 was not operated at more than 404 MW per hour. Tr. at 980-83.¹¹⁴ Mr. Van Gieson also noted (which was confirmed by Mr. Houston) that during the one-year period immediately after the project, TVA operated Colbert Unit 5 to achieve a 509-MW maximum hourly net generation rate. See Tr. at 983-84.¹¹⁵ Mr. Van Gieson also used other data reported by TVA in its Monthly Operating Statistics Reports to determine an emissions factor measured in units of emissions per megawatt hour of net generation. EPA Enforcement Ex. 277, at 42-43; EPA Enforcement Ex. 174. By combining this emissions factor with the maximum hourly net generation rates for the pre-change and post-change

(continued)

do not constitute routine maintenance, repair and replacement under the NSR routine exception. There, we applied the Agency's four factor test to the project and found that the magnitude of the renovation and the length of time to plan and to implement TVA's work at Unit 5 to be significant facts that cut against considering this construction work to be "routine." Moreover, the rehabilitation of this unit was designed to fundamentally change the manner in which the unit operated. These facts, as well as others more fully discussed in Part III.C.4, in our view establish that the project was not "routine" in either of the two regulatory contexts.

¹¹³ TVA's monthly operating reports record the maximum hourly net generation during the reporting month.

Mr. Houston's testimony showed that Colbert Unit 5 achieved a maximum hourly net generation rate in October 1977 to September 1978 of 404 MW, for the same period in 1978-79 of 399 MW, in 1979-80 of 397 MW, in 1980-81 of 389 MW, and in 1981-82 of 364 MW.

¹¹⁵ Mr. Houston's testimony showed that Colbert Unit 5 achieved a maximum hourly net generation rate in October 1982 to September 1983 of 509 MW, and in the same period of 1983-84 of 495 MW. Tr. at 983-84.

periods, Mr. Van Gieson determined that the physical changes made to Colbert Unit 5 resulted in an increase in the unit's maximum hourly emissions rate for NO_x, SO₂ and PM. EPA Enforcement Ex. 277, at 43. The emissions rate increase calculated by Mr. Van Gieson was an increase for each pollutant of approximately 25% as a result of the physical changes made to Colbert Unit 5.

TVA argues that Mr. Van Gieson's calculation of the emissions rate increase at Colbert Unit 5 is erroneous or inadequate for two reasons, both related to Mr. Van Gieson's reliance on the "maximum hourly net generation" of the unit. First, TVA argues that the information used by Mr. Van Gieson was the maximum hourly generation rate "actually achieved," rather than the "maximum achievable" rate. TVA Post-Hearing Brief at 49. TVA argues that it presented evidence that the "nominal" derating of the unit to 400 MW prior to the project did not reflect a physical limitation on the maximum generation rate, "but rather reflected, at least in part, an administrative decision by TVA to operate Colbert Unit 5 at a lower generation rate than the unit was capable of in order to improve the long-term reliability of the unit." Id. at 50. TVA cites the NSPS analysis in the WEPCO case as an example demonstrating that actual achieved rates may be lower than maximum achievable rates. Id. Second, TVA argues that "EPA Enforcement ignored in its calculations the fact that emission rates are not always directly proportional to the electric generation rates that a unit produces." Id. (emphasis by TVA). TVA argues that it presented evidence that "the efficiency of the turbine [at Colbert Unit 5] was significantly lower before the project than it was after the project." Id. TVA argues that because efficiency was improved, it is not possible to reasonably conclude that the increased actual generation rate after the project translates to an increased emissions rate. Id. at 50-51. Both of these arguments must be rejected for the following reasons.

First, we reject TVA's argument that an alleged improvement in turbine efficiency may explain the increased electrical generation. TVA did not provide any evidence that turbine efficiency problems were fully responsible for the reduced generation during the five-year period prior to the project. To the contrary, TVA's witness only stated that "[t]hese problems may or may not account for the full electrical capability reduction of the unit." TVA Ex. 9, at 14 (Houston pre-filed testimony). This inconclusive statement is not sufficient to rebut other evidence in the record showing that the derating prior to the change was caused, at least in part, by problems with the boiler and which were unrelated to the turbine. Specifically, the GADS data listed problems with the boiler steam chest, not any aspect of the turbine, as the reason for the derating in the period of July 1980 through February 1982. *Id.* at 13.

Second, we also reject TVA's argument that we should not look to the actual achieved rate of electrical generation as showing the maximum achievable rate in this case. The WEPCO case cited by TVA is instructive on this issue. In that case, WEPCO had five units that it was proposing to renovate, and EPA ini-

tially looked to the pre-project actual achieved generation rate and the projected post-project restored generation rate (similar to the evidence submitted by EPA Enforcement in the present case) to conclude that the maximum hourly emissions rate would increase as a result of the project. WEPCO, 893 F.2d at 913. Before WEPCO sought judicial review of this determination, WEPCO requested reconsideration by the EPA on essentially the same grounds raised by TVA in this case, that the achieved rate only reflects an administrative decision and did not reflect the achievable emission rate. Id. On reconsideration, EPA allowed WEPCO to conduct five ten-hour tests at each unit to determine the units' maximum capacity, as a means of supplementing the information regarding actual operating history. Id. Based on those tests, EPA agreed that two of the units could be operated at their design capacity. However, it concluded that three of the units could not be operated at design capacity and, therefore, the restoration project would increase their achievable capacity by restoring them to their original design capacity. Id. at 914-16 & n.9.

WEPCO then objected to this supplemental determination and requested review by the Seventh Circuit. In seeking review, WEPCO raised two arguments, the first of which was that the pre-project historical operating data "reflect voluntary decisions by WEPCO regarding safety considerations * * * and an electricity demand which did not require operation of the units at higher capacities." *Id.* at 914. The Seventh Circuit rejected this argument, saying, "WEPCO's first assertion is easily dismissed. The EPA's choice of the 1987 figures was based entirely upon WEPCO's own data" and the subsequent tests resulted in a revision for only two units. *Id.* This discussion and the Seventh Circuit's conclusions demonstrate an important principle that we apply to the present case: operating data showing the achieved maximum generation rate may be relied upon as evidence of the maximum achievable rate in the absence of tests demonstrating a higher achievable rate. It is also worth noting that later in the decision, the Seventh Circuit stated that "EPA cannot reasonably rely on a utility's own unenforceable estimates of its annual emissions." *Id.* at 917.

In the present case, the admitted fact that TVA never operated Colbert Unit 5 at an hourly rate greater than 404 MW during the entire five-year period prior to the project is compelling evidence that Colbert Unit 5 could not achieve an hourly generation rate comparable to the hourly rate of 509 MW achieved in the year immediately after the project. This evidence is further supported by the GADS data showing a continuous derating from December 5, 1975 to February 1982 of 78-120 MW. TVA Ex. 9, at 13 (Houston pre-filed testimony). TVA has not rebutted this evidence with actual test data demonstrating that Colbert Unit 5 could achieve a higher rate prior to the project. TVA has only offered testimony by Mr. Houston regarding his interviews with maintenance personnel in mid-2000 as to their recollection of the capability of Colbert Unit 5 in the period immediately prior to the project in 1982. We conclude that this hearsay testimony is unrelia-

ble¹¹⁶ and cannot substitute for the rigorous testing under prescribed protocols that is normally required by EPA before it accepts data other than the actual achieved rate. *See WEPCO*, 893 F.2d at 914-15 & nn.7 & 8. Indeed, in the *WEPCO* case (the one from which WEPCO sought court review), EPA Administrator Lee M. Thomas stated that EPA would not accept mere "assertions that higher-than-actual capacity could be achieved on a economically sustainable basis." Letter from Lee M. Thomas to John W. Boston, WEPCO, at 5 (Oct. 14, 1988).

Accordingly, we conclude that a preponderance of the evidence in the record shows that the physical changes to Colbert Unit 5 removed a physical limitation on the operating potential of the unit and restored it to its original design capacity, thereby resulting in an increase in the maximum hourly emissions rate achievable by the unit for NO_x, SO₂ and PM. Therefore, upon completion of the physical changes at Colbert Unit 5, that unit became subject to the operating restrictions of 40 C.F.R. part 60, subpart Da. TVA has stipulated that it "did not conduct performance testing or perform record keeping and reporting" under subpart Da. Accordingly, we find that TVA violated the NSPS with respect to the operation of Colbert Unit 5 after the physical changes at that unit.

In addition, in terms of TVA's compliance with the pre-1983 nonattainment NSR provisions of the Alabama SIP, the increased maximum hourly emissions rate means that the unit's potential SO₂ emissions increased from 78,104 tpy before the project to 97,630 tpy of SO₂ after the project. See EPA Enforcement Ex. 281. This increase greatly exceeds the 100 tpy potential emissions increase necessary to trigger the pre-1983 nonattainment NSR provisions of the Alabama SIP. See Regulation Stipulation tab 16, § 16.3.2. Accordingly, we find that TVA violated the CAA by failing to obtain a preconstruction nonattainment NSR permit under the Alabama SIP.

F. Violations of the State Minor Modification Permit Requirements

As noted above in our discussion of the statutory background in Part III.B, the States of Tennessee, Kentucky and Alabama, where TVA's nine coal-fired power plants are located, require as part of their SIPs that source owners obtain "minor" NSR permits under certain circumstances. In the present case, EPA Enforcement argues that TVA was required to obtain a minor source permit for the following projects:

When EPA Enforcement cross-examined Mr. Houston regarding his interviews with the TVA maintenance personnel responsible for Colbert Unit 5 during the relevant time period, Mr. Houston could not answer many questions going to relevant dates of events and the basis of the non-testifying declarant's recollections. See Tr. at 985-93, 995. While hearsay evidence is commonly admitted in administrative adjudications, we need not rely on such testimony when, as here, it may be unreliable. See, e.g., 40 C.F.R. § 22.22(a) (allowing unreliable evidence to be excluded).

- 1. Under the Tennessee SIP for Memphis County, Allen Unit 3. EPA Enforcement Post-Hearing Brief at 74-75 (citing S1200-3-9-.01-(1) (Memphis/Shelby County portion of SIP)).
- 2. Under the Tennessee SIP, Bull Run Unit 1, Cumberland Unit 1 and Unit 2, John Sevier Unit 3, and Kingston Unit 6 and Unit 8. *Id.* at 75-76, 78-83 (citing 1200-3-9-.01-(1) (general Tennessee SIP)).
- 3. Under the Alabama SIP, Colbert Unit 5 and Widows Creek Unit 5. *Id.* at 77-78, 89-90 (citing Alabama Reg. 16.1.1(a)).

The Compliance Order also alleged that projects at the units located in Kentucky were each required to have a Kentucky "minor" NSR permit. However, as noted in Part III.A of this decision, EPA Enforcement has not made any further argument in its post-hearing briefs that TVA violated the requirements of the Kentucky minor NSR permitting program. Accordingly, such allegations of the Compliance Order appear to have been abandoned and, therefore, are not sustained. Our discussion in this part will focus on the remaining projects and state minor permitting requirements.

TVA argues that the applicable minor NSR permitting regulations under the Alabama and Tennessee SIPs provide an exemption for "routine maintenance, repair and replacement" and that each of these projects fall within that exemption. In addition, TVA argues that the minor NSR permitting requirements of these SIPs "apply only where there is an increase in potential emissions or in emissions rates, the emission increase test used in the federal NSPS program." TVA Post-Hearing Brief at 120. TVA argues that EPA Enforcement failed to produce "any evidence that the identified projects at TVA's Tennessee and Alabama units resulted in increased emissions rates." *Id.* For the following reasons, these arguments must be rejected.

1. Tennessee Minor NSR Permitting Requirements

In the present case, Allen Unit 3 is located within the jurisdiction of the Memphis/Shelby County permitting authority and Bull Run Unit 1, Cumberland Unit 1 and Unit 2, John Sevier Unit 3, and Kingston Unit 6 and Unit 8 are all located within the jurisdiction of the Tennessee state permitting authority. While the regulations applicable to the Memphis/Shelby County area and the regulations applicable to the remainder of Tennessee are different in a number of particular respects, the specific regulations governing the applicability of the minor NSR permitting requirements are identical in both sets of regulations. Accordingly, for simplicity, we will refer to the broader Tennessee SIP requirements as the surrogate for both sets of regulations.

The Tennessee SIP requires source owners to obtain a permit before beginning modification of an air contaminant source. Specifically, the SIP states as follows:

Except as specifically exempted in Rule 12-3-9-.04, no person shall begin the construction of a new air contaminant source or the modification of an air contaminant source which may result in the discharge of air contaminants without first having applied for and received from the Technical Secretary a construction permit for the construction or modification of such air contaminant source.

Regulation Stipulation tab 1, § 16-77 (S1200-3-9-.01(1)); *id.* tab 3 (1200-3-9-.01(1)). The term "air contaminant source" as used in this regulation is defined as follows:

Air Contaminant Source is any and all sources of emission of air contaminants, whether privately or publicly owned or operated. Without limiting the generality of the foregoing, this term includes all * * * heating and power plants and stations * * *.

Id. tab 1, § 16-46(A); id. tab 4 (1200-3-2-.01(b)); id. tab 5 (1200-3-2-.01(b)). "Air Contaminant" is "particulate matter, dust, fumes, gas, mist, smoke, or vapor, or any combinations thereof." Id. tab 1, § 16-46(A); id. tab 4 (1200-3-2-.01(a)); id. tab 5 (1200-3-2-.01(a)). The Tennessee minor NSR rules define "modification" as follows:

Modification is any physical change in or change in the method of operation of any air contaminant source, which increases the amount of any air contaminant (with an applicable emission standard) emitted by such source or which results in the emission of any air contaminant (with an applicable emission standard) not previously emitted * * *.

Id. tab 1, § 16-46(A); see also id. tab 4 (1200-3-2-.01(aa)); id. tab 5 (1200-3-2-.01(aa)). The regulation also states that physical change shall not include "routine maintenance, repair and replacement." Id. tab 1, § 16-46(A); id. tab 4 (1200-3-2-.01(aa)); id. tab 5 (1200-3-2-.01(aa)).

EPA Enforcement argues that the changes made to Allen Unit 3, Bull Run Unit 1, Cumberland Unit 1 and Unit 2, John Sevier Unit 3, and Kingston Unit 6 and Unit 8, were "physical changes" within the meaning of these regulations

¹¹⁷ The definition of "modification" in the general Tennessee SIP contains an immaterial difference in that the two parenthetical statements used in the definition are "(to which an emission standard applies)," rather than as set forth in the text above.

which increased the amount of NO_X, SO₂ and PM emitted by the units. EPA Enforcement argues that increases in the amount of emissions must be measured based upon an actual-to-potential test.

As noted above, TVA argues that the changes to these units were not "physical changes" because the changes were routine maintenance, repair and replacement. TVA Response to Initial Brief at 14. TVA argues that the routine maintenance exception should be applied consistent to the similar exception under the PSD and nonattainment NSR programs. *Id.* Because, as discussed above in Part III.C, we have found that the identical routine maintenance exception under the PSD and nonattainment NSR programs does not apply to any of the changes at issue, we likewise conclude that this exception does not apply to those changes under the Tennessee SIP minor NSR program.

TVA also argues that the emissions increase test under the Tennessee SIP minor NSR program is not the actual-to-potential test suggested by EPA Enforcement, but instead is the maximum potential hourly rate increase applicable under the federal NSPS program. *Id.* at 14-15. TVA argues that the NSPS emissions test should apply because the definition of "modification" under the Tennessee minor NSR permit is identical to the definition of that term under the federal NSPS regulations. *Id.* (citing 40 C.F.R. § 60.2). This argument must be rejected because the federal NSPS emissions increase test (maximum hourly emissions rate) is derived from the regulations at 40 C.F.R. § 60.14, not from the definition of modification at section 60.2. The Tennessee SIP provisions identified in the parties' stipulations do not contain any provision prescribing in detail the method for calculating an emissions increase for a modification similar to that set forth in section 60.14 of the federal NSPS regulations. Accordingly, we find no basis to incorporate that set of regulatory requirements into the definition of "modification" in the Tennessee SIP.

For a similar reason, we also reject EPA Enforcement's arguments that the Tennessee SIP minor NSR modification definition should be read to incorporate the actual-to-potential test. The regulation from which the actual-to-potential test arises, 40 C.F.R. § 52.21(b)(21), has no analogue within the Tennessee minor NSR regulations. Accordingly, we again turn to the actual-to-projected-actual test¹¹⁸ discussed above in Part III.D.5, and determine that, through Mr. Van Gieson's testimony, EPA Enforcement has sustained its burden of showing that an emissions increase should have been predicted and that TVA was thus required to obtain a minor NSR permit from the applicable Tennessee or Memphis/Shelby County permitting authority.

¹¹⁸ In the absence of another legally prescribed methodology, here, as before, we find this test a reasonable means of measuring emissions increases. *See WEPCO*, 893 F.2d 901.

Because the minor NSR regulations do not have a "significance" threshold of 40 tpy for NO_X and SO₂ and 25 tpy for PM, there are more violations of the minor permitting requirements than we found above with respect to PSD and nonattainment NSR. In particular, we find that TVA was required to obtain a Tennessee minor NSR permit for the following pollutants at the indicated units:

	NO _x	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		X
John Sevier Unit 3	X	X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	X

TVA stipulated that it did not have a Tennessee minor NSR permit for any of these pollutants and physical changes at these units. Joint Fact Stipulation ¶15. Accordingly, TVA violated the Tennessee SIP provisions prohibiting construction without a permit.

2. Alabama Minor NSR Permitting Requirements

Colbert Unit 5 and Widows Creek Unit 5 are located within Alabama and, therefore, are potentially subject to the Alabama minor NSR permitting requirements. The Alabama SIP states as follows:

Permit to Construct. Any person building, erecting, altering, or replacing any article, machine, equipment, or other contrivance, the use of which may cause the issuance of or an increase in the issuance of air contaminants or the use of which may eliminate or reduce or control the issuance of air contaminants, shall first obtain authorization for such construction from the Director in the form of a Permit to Construct.

Regulation Stipulation, tab 19, § 16.1.1(a); see also id. tab 20, § 16.1.1(a).119 The

¹¹⁹ The version of the applicable regulation at tab 20 of the Regulation Stipulation became effective October 28, 1985, and contains immaterial changes from the version quoted in the text above.

term "air contaminant" as used in this regulation is defined as follows:

"Air Contaminant" shall mean any solid, liquid, or gaseous matter, any odor, or any combination thereof, from whatever source.

Id. tab 21, § 1.2.1. The terms "building, erecting, altering, or replacing" as used in section 16.1.1 are not defined by the Alabama SIP.

EPA Enforcement argues that the changes made to Colbert Unit 5 and Widows Creek Unit 5 fall within the terms "building, erecting, altering, or replacing" and that those changes increased the amount of NO_x, SO₂ and PM emitted by the units. EPA Enforcement argues that increases in the amount of emissions must be measured based upon an actual-to-potential test.

As noted above, TVA argues that the term "alteration" as used in section 16.1.1 is synonymous to "modification," which is defined by the Alabama SIP (that definition is substantially the same as the Tennessee definition of "modification" quoted above). TVA Response to Initial Brief at 16. TVA argues that because the two terms are ordinarily synonymous, we should apply the regulatory definition of "modification" in place of the term "alteration" as used by section 16.1.1. There are two errors in this argument. First, while the terms "alteration" and "modification" may be generally synonymous, it however does not follow that a highly detailed and specific regulatory definition of one term can be substituted for the other. Instead, we conclude that the much broader and more general plain meaning of "alteration" must be used in the absence of anything in the regulations suggesting a narrower regulatory definition. Second, by its suggested contrivance of incorporating the definition of "modification" in place of "alteration," TVA suggests that "routine * * * replacement" was not intended to be included as a form of alteration. Id at 17. Such an interpretation would violate the plain meaning of the regulatory text. Section 16.1.1 specifically includes "replacing" among its list of changes that may require a permit and does not provide for an exception for "routine * * * replacement." We cannot by interpretation create an exception where one does not exist.

TVA also argues that the emissions increase test under the Alabama SIP minor NSR program is not the actual-to-potential test suggested by EPA Enforcement, but instead is the maximum potential hourly rate increase applicable under the federal NSPS program. *Id.* at 17. TVA argues that the NSPS emissions test should apply because the definition of "modification" under the Alabama SIP is substantially the same as the definition of that term under the federal NSPS regulations. *Id.* (citing 40 C.F.R. § 60.2). This argument must be rejected for two reasons. First, as noted above, the Alabama SIP minor NSR permitting requirements are based upon "building, erecting, altering, or replacing," not upon "modification" — the linchpin for NSPS coverage. *See* Regulation Stipulation, tab 19, § 16.1.1(a); *see also id.* tab 20, § 16.1.1(a). Second, the federal NSPS emissions

increase test (maximum hourly emissions rate) is derived from the regulations at 40 C.F.R. § 60.14, not the definition of modification at section 60.2. Not only do the Alabama SIP minor NSR provisions fail to mention "modification," but they also do not contain any provision prescribing in detail the method for calculating an emissions increase for a modification similar to that set forth in section 60.14 of the federal NSPS regulations. Accordingly, we find no basis to incorporate the "maximum hourly emissions rate" requirement of the federal NSPS regulation into section 16.1.1 of the Alabama SIP governing when a minor NSR permit must be obtained.

For a similar reason, we also reject EPA Enforcement's arguments that the Alabama SIP minor NSR modification definition should be read to incorporate the actual-to-potential test. The regulation from which the actual-to-potential test arises, 40 C.F.R. § 52.21(b)(21), has no analogue within the Alabama minor NSR regulations. Accordingly, we turn once more to the actual-to-projected-actual test discussed above in Part III.D.5, and determine that, through Mr. Van Gieson's testimony, EPA Enforcement has sustained its burden of showing that an emissions increased occurred and that TVA was thus required to obtain a minor NSR permit from the applicable Alabama permitting authority.

Because the minor NSR regulations do not have a "significance" threshold of 40 tpy for NO_X and SO₂ and 25 tpy for PM, there are more violations of the minor permitting requirements than we found above with respect to PSD and nonattainment NSR. In particular, we find that TVA was required to obtain an Alabama minor NSR permit for the following pollutants at the indicated units:

	NO _x (tpy)	SO ₂ (tpy)	PM(tpy)
Colbert Unit 5	X	X	X
Widows Creek Unit 5	X	X	X

TVA stipulated that it did not have an Alabama minor NSR permit for any of these pollutants and changes at these units. Joint Fact Stipulation ¶ 15. Accordingly, TVA violated the Alabama SIP provisions prohibiting construction without a permit.

G. The Appropriate Remedies for TVA's Violations

The Compliance Order states, in lettered paragraphs from (a) to (i), various actions that TVA must take in order to remedy the violations identified in the Compliance Order. TVA has objected to these remedies, arguing generally that many of them are not authorized by the CAA. In this part, we consider TVA's arguments and EPA Enforcement's responses.

In summary, the Compliance Order directs TVA to undertake the following actions to remedy its violations of the CAA: (1) TVA shall "provide a detailed schedule with appropriate milestones submitted for approval by EPA for achieving compliance with all NSR (both PSD and nonattainment NSR) requirements," which schedule shall identify the pollution control technology to be installed on the plants with nothing less protective than selective catalytic reduction ("SCR") for NO_x emissions control. Compliance Order § IV.1(a); (2) TVA shall provide a schedule for complying with all NSPS requirements, § IV.1(b); (3) TVA shall enter into a "Federal Facilities Compliance Agreement" regarding such schedules, id. § IV.1(c);¹²⁰(4) TVA shall submit to the appropriate federal, state and local authority applications for NSR permits and Title V121 operating permits for the modifications identified in the order, id. § IV.1.(d); (5) TVA shall provide EPA an audit of each of its coal-fired power plants to identify all physical changes made since 1977 that may have triggered the NSR and NSPS requirements, id. § IV.1(e); (6) TVA shall prepare a compliance schedule and Federal Facilities Compliance Agreement for all violations identified in the audit. Id. § IV.1(f), (g);¹²² and (7) finally, TVA must retire and not use certain SO₂ allowances under CAA Title IV. Id. § IV.1(h).

TVA raises a number of objections to the remedy sections of the Compliance Order. Briefly, TVA objects to the remedy requests in sections IV.1(a), (b), (d), (f) and (g) with respect to submission of compliance schedules and the means for determining best available control technology ("BACT") with respect to NO_x. TVA also objects to the request that TVA be required to provide an audit as set forth in section IV.1(e) and to the request that it be required to surrender SO₂ allowances in section IV.1(h). These arguments will be discussed below.

1. Compliance Schedules, Applications, BACT for NO_X and Related Issues

TVA has raised a number of related arguments regarding the compliance schedule and permit application remedies under sections IV.1(a), (b), (d), (f) and (g). Specifically, TVA argues that EPA Enforcement has no authority to specify that the control technology for NO_X shall be no less protective than SCR. TVA Post-Hearing Brief at 107. Rather, TVA argues that control technology determinations must be made on a case-by-case basis by the appropriate federal, state or local authority. *Id.* at 108. TVA argues further that the compliance schedule and

¹²⁰ TVA has not objected to this requested remedy and, accordingly, it is sustained.

¹²¹ TVA has not objected to this requested remedy (that it be required to submit applications for Title V operating permits) and, accordingly, it is sustained.

¹²² TVA has not objected to this requested remedy in so far as it concerns enter-ing into a Federal Facilities Compliance Agreement and, accordingly, it is sustained.

control technology requirements of the Compliance Order impermissibly "fore-close options available to a stationary source under the Clean Air Act and EPA's regulations, including the option to net out of new source review." *Id.*

EPA Enforcement acknowledges that BACT must be determined on a case-by-case basis by the applicable permitting authority.¹²³ EPA Enforcement states that the Compliance Order simply "sets forth the minimum level of controls [EPA Enforcement] will accept to resolve the case." EPA Enforcement Reply Brief at 65. EPA Enforcement states further as follows:

[B]y identifying SCR as the minimum acceptable NO_X pollution control device, EPA was merely treating TVA as it would a nongovernmental entity, and not undermining the statutory BACT process. EPA was not, as TVA alleges, attempting to usurp the BACT case-by-case analysis performed by the permitting agency, as set forth in the Act and regulations. Indeed, the [Compliance Order] instructs TVA to submit applications for the appropriate federal, state and local air NSR permits, which applications should include a BACT/LAER analysis, as appropriate.

Id. at 66.¹²⁴ Because EPA Enforcement has interpreted the Compliance Order's statements with respect to SCR as BACT for NO_X emissions controls as something to be secured through settlement rather than as a substitute for traditional BACT/LAER analysis, we hold that EPA Enforcement shall be bound by this interpretation. Accordingly, TVA is not bound by EPA Enforcement's assertion, as made in the Compliance Order, that SCR is the minimum pollution control for

¹²³ The BACT requirement is defined in the regulations as follows:

[[]BACT] means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

⁴⁰ C.F.R. § 52.21(b)(12); accord CAA § 169(3), 42 U.S.C. § 7479(3). As the Board has noted on prior occasions, "[t]he requirements of preventing violations of the NAAQS and the applicable PSD increments, and the required use of BACT to minimize emissions of air pollutants, are the core of the PSD regulations." In re Encogen Cogeneration Facility, 8 E.A.D. 244, 247 (EAB 1999); accord In re Hawaii Elec. Light Co., 8 E.A.D. at 73.

¹²⁴ "BACT/LAER" stands for "Best Available Control Technology/Lowest Achievable Emission Rate." Each of these acronyms refers to technological standards established by different sections of the CAA. BACT is the standard from the PSD provisions of the CAA and LAER is the standard for nonattainment NSR provisions.

NO_x.125

It further appears that both TVA and EPA Enforcement generally agree that an appropriate remedy for TVA's failure to obtain preconstruction PSD, nonattainment NSR and minor NSR permits is for TVA to be required to apply for such permits. *See* EPA Enforcement Reply Brief at 66 ("the [Compliance Order] instructs TVA to submit applications for the appropriate federal, state and local air NSR permits, which applications should include a BACT/LAER analysis, as appropriate."); TVA Post-Hearing Brief at 118 ("That determination [BACT] must be made by the appropriate state and be based upon a case-by-case, site-specific balancing, of energy, environmental and economic impacts and other costs of the controls available to the units."). ¹²⁶

Although TVA appears to concede that requiring it to obtain the necessary NSR permits is generally an appropriate remedy, TVA nevertheless argues that the compliance schedule and control technology requirements of the Compliance Order impermissibly "foreclose options available to a stationary source under the Clean Air Act and EPA's regulations, including the option to net out of new source review." TVA Post-Hearing Brief at 108. TVA thus argues that it may avoid the permitting requirements by electing to reduce emissions elsewhere at the pollution sources — in other words, by making creditable contemporaneous reductions to qualify for "netting" under 40 C.F.R. § 52.21(b)(3)(ii).

This argument must be rejected on the grounds that TVA has failed to show, based on evidence in the record of this proceeding, that it made the required "contemporaneous" emissions reductions (i.e., emissions reductions in the period between five years before the construction commenced and the date when the predicted increases from the physical change would occur). See, e.g., In re Hawaii Elec. Light Co., PSD Appeal Nos. 97-15 to -23, slip op. (EAB, Nov. 25, 1998), 8 E.A.D. 66, 74-82. Had TVA sought to defend against the Compliance Order's

¹²⁵ However, in the case-by-case BACT determination process conducted by the applicable permitting agency (*see infra* note 127), EPA Enforcement, or any other appropriate part of the Agency, is not precluded from commenting on the BACT analysis or other parts of the permit, including but not limited to SCR being the appropriate minimum pollution control.

¹²⁶ TVA does argue that EPA does not have "authority for its order for compliance schedules and permit applications" under CAA § 167, 42 U.S.C. § 7477. TVA Response to Initial Brief at 75. TVA, however, does not argue that such authority is lacking under CAA § 113(a), 42 U.S.C. § 7413(a), which specifically authorizes the Agency to issue administrative orders requiring the respondent to "comply with the requirements or prohibitions" that the respondent has violated. Since we have found that TVA violated the CAA by failing to obtain preconstruction NSR permits, it is appropriate that TVA be required under section 113 to comply by applying for such permits. Thus, we conclude that section 113(a) provides adequate authority for these portions of the Compliance Order and, therefore, we do not address TVA's assertions regarding the scope of EPA's authority under CAA § 167.

request for relief that TVA must obtain NSR permits based on its claiming contemporaneous emissions reductions, it should have done so in this proceeding. The "netting" option for avoiding the requirement to obtain an NSR permit is provided by the regulatory definition of "net emissions increase." See, e.g., 40 C.F.R. § 52.21(b)(3) (1984). As discussed in Part III.D above, we have found, based upon the record of this case, that the physical changes made by TVA to thirteen of its coal-fired units resulted in significant "net emissions increases" under the applicable regulatory provisions. TVA, therefore, is barred from subsequently attacking this determination by attempting to demonstrate contemporaneous emissions reductions that offset the emissions increases demonstrated on the record of this case. Accordingly, we reject TVA's contention that it may "net out of new source review."

For the foregoing reasons, we sustain the Compliance Order's requirement that TVA apply for, and obtain, PSD, nonattainment NSR and minor NSR permits for the physical changes made to the units and with respect to the pollutants indicated in Parts III.D, III.E and III.F of this decision.¹²⁷ Such applications must be filed, and permits obtained, by TVA for the following units and pollutants:¹²⁸

For PSD and nonattainment NSR:

Chart No.2

	NO_X	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	

¹²⁷ TVA's permit applications should be governed by the rules that are in force at the time each application is submitted. Thus, the applications should be submitted to the agency with authority as of the date of the application to issue permits for the particular pollutant in each area. TVA's applications will open a new administrative record before those agencies with respect to the BACT/LAER determinations and the analysis of appropriate pollution controls should take into account all information submitted into the record regarding any factors relevant under the applicable statutory or regulatory requirements, such as technological feasibility and environmental impacts. See, e.g., In re Pennsauken County, N.J. Resource Recovery Facility, 2 E.A.D. 667, 670-71 nn.10-12 (Adm'r 1988) (noting that the adequacy of the administrative record is judged as of the close of the record, absent extraordinary circumstances). Thus, we reject TVA's contention that the analysis should look to the circumstances that existed when TVA made the physical changes to its plants. TVA is responsible for the delay in applying for the applicable permits and, therefore, cannot argue that requiring current technology somehow causes it prejudice. That the analysis should not be based on substantially outdated evidence is further confirmed by 40 C.F.R. § 52.21(r)(2), which states that a permit is "invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time."

¹²⁸ These summary charts are the ones also set forth in Part III.A of this decision.

Colbert Unit 5	X	X	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		
John Sevier Unit 3	·	X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	
Paradise Unit 1	X		
Paradise Unit 2	X		
Paradise Unit 3	X		
Shawnee Unit 1	X	X	
Shawnee Unit 4	X	X	

For minor NSR under the applicable SIPs:

Chart No.3

	NO _X	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		X
John Sevier Unit 3	X	X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	X
Colbert Unit 5	X	X	X
Widows Creek Unit 5	X	X	X

2. Forfeiture of Title IV (Acid Deposition Control) SO₂ Allowances

TVA objects to the request of Section IV.1(h) of the Compliance Order that

TVA surrender certain SO₂ "allowances"¹²⁹ allocated to it under Title IV of the CAA. According to EPA Enforcement, the surrender of these allowances is necessary to bring TVA into compliance with the Act and to compensate the environment for TVA's past NSR and PSD violations. EPA Enforcement Initial Brief at 56; EPA Enforcement Post-Hearing Brief at 175. Section IV.1(h) of the Compliance Order states:

Sulfur Dioxide Allowances. For any reductions in sulfur dioxides that result from the addition of pollution control equipment under the federal facility compliance agreement to be entered into pursuant to paragraphs 1(c) and 1(g) above, sulfur dioxide allowances from Title IV of the Clean Air Act equivalent to the reductions must be retired and cannot be used by TVA or sold to any other utility.

TVA objects to this provision on several grounds, including that the Agency lacks the authority under section 113 of the Act to require surrender of its existing SO₂ allowances, and that the provision lacks the specificity required by section 113(a)(4). See TVA Response to Initial Brief at 81-89; TVA Reply Brief at 62-66.

Title IV of the CAA, added by the 1990 CAA amendments, is designed to reduce emissions of pollutants contributing to the problem of acid deposition (often referred to as "acid rain"). With regard to SO₂ emissions, the Act requires a phased implementation ("Phase I" and "Phase II") of a national cap of 8.95 million tons per year from electric utility plants such as the ones at issue in this matter. The reduction of SO₂ is achieved by giving affected units allowances, which then determines the amount of annual SO₂ the source is authorized to emit. A unit subject to Title IV may not emit SO₂ in excess of the number of allowances held for that unit for that year by the unit's owner or operator. CAA § 403(g), 42 U.S.C. § 7651b(g). The number of allowances allocated to each unit is determined through various formulae utilizing a unit's emissions and fuel consumption.

During Phase I of the program, effective from 1995 through 1999, limits were imposed on the 110 largest sulfur-emitting electric utility plants in twenty-one eastern and midwestern states. CAA § 404(a), 42 U.S.C. § 7651c(a). The basic SO₂ allocation formula for Phase I involved multiplying an emissions rate of 2.5 pounds of SO₂ per million British Thermal Units ("BTUs") of heat by a unit's "baseline" fuel consumption (generally the unit's 1985-87 average). *Id.* ¹³⁰ Phase II,

¹²⁹ The term "allowance" is defined as an "authorization, allocated to an affected unit by the Administrator under this subchapter, to emit, during or after a specified calendar year, one ton of sulfur dioxide." CAA § 402(3), 42 U.S.C. § 7651a(3).

¹³⁰ TVA maintains that five of the nine plants at issue in this case were subject to Phase I. TVA Response to Initial Brief at 84. These appear to be Colbert, Allen, Cumberland, Paradise, and Shawnee. See CAA § 404 Table A, 42 U.S.C. § 7651c Table A.

effective in January 2000, applies to all fossil fuel-fired electricity generating units and employs a somewhat similar method to determine SO₂ allowances.¹³¹ However, for almost all the regulated sources, the emissions rate by which the baseline is to be multiplied is reduced from 2.5 pounds of SO₂ per million BTUs to 1.2 pounds to exact further reductions of SO₂ emissions. In certain instances, the applicable formulae utilize a unit's actual or allowable 1985 emissions rate in determining the number of allowances allocated. *See, e.g.*, CAA §§ 404(a), 405(c), 42 U.S.C. §§ 7651c(a), 7651d(c).

According to EPA Enforcement, because of the alleged NSR and PSD violations, the incorrect emissions data from 1985 "may have been used" in allocating TVA's SO₂ allowances and "[t]hus the current allocation of SO₂ allowances to TVA plants may be improperly inflated." EPA Enforcement Initial Brief at 57 (emphasis added). "Consequently, any plan undertaken to return TVA to full compliance with the Clean Air Act must include the reallocation of SO₂ allowances to TVA. Similarly, to return the environment to where it would have been but for TVA's NSR/PSD violations, TVA should surrender a quantity of allowances equal to the amount of emissions it emitted based upon its reliance on its improper allowances * * *." Id. EPA Enforcement further asserts that TVA must offset any excess emissions that occurred as a result of its violations. Id. Upon review, EPA Enforcement has failed to convince us that any forfeiture or reallocation of allowances is appropriate under the current state of the record.

Although it is certainly conceivable that the CAA violations at certain of TVA's facilities may have resulted in a misallocation of SO₂ allowances, EPA Enforcement cites to no evidence that any such misallocation actually occurred. Rather, EPA Enforcement merely speculates that the violations may have had some effect on the 1985 SO₂ emission levels and that this may have resulted in TVA being awarded more SO₂ allowances than it would have otherwise been entitled under the applicable allowance formula. Indeed, EPA Enforcement itself acknowledges that it has not completed its analysis on the extent of the violations. *Id.* at 56.¹³² As far as we can tell from the record before us, it may well be that

¹³¹ As EPA notes, "[t]he allowance allocation scheme established under Title IV is complex, relying on numerous formulae." EPA Enforcement Initial Brief at 57. The summary in the text above is not intended as a comprehensive statement of these formulae.

¹³² EPA Enforcement states as follows:

TVA must comply with a reallocation of its Phase II allowances, which will be performed once the extent of its NSR/PSD noncompliance is ascertained. Second, it must offset emissions equal to the amount of excess allowances it may have relied on for the period beginning in 1995 and ending when the reallocation is complete. Third, TVA must provide emission reductions, perhaps through allowance forfeiture, to offset the excess emissions that occurred under Title I in order to render the Environment whole.

once EPA Enforcement has completed its analysis, EPA Enforcement may determine that SO₂ allowances were not improperly allocated.¹³³ Similarly, although EPA Enforcement argues that the environment should be compensated for excess emissions during the period of violation through a surrender of existing SO₂ allowances, EPA Enforcement has not provided the Board with sufficient data to determine if such a surrender is appropriate in this case. *See id.* at 56 n.55 ("At this time, EPA Enforcement has not determined the exact amount of allowances that would have to be retired in order for there to be a sufficient remedy under both Title IV and Title I, but when that amount is determined EPA Enforcement is prepared to seek forfeiture of only that amount.").

Under these circumstances, the record is insufficient to support the surrender of SO₂ allowances contemplated by section IV.1(h) of the Compliance Order. Moreover, based on the representations in EPA Enforcement's own briefs, it appears as if EPA's request for relief is not yet ripe.¹³⁴ If, however, upon completion of its analysis, EPA Enforcement continues to believe that a reallocation and/or surrender of SO₂ allowances is appropriate, EPA Enforcement is not precluded by this order on reconsideration from pursuing that avenue of relief in an appropriate proceeding.¹³⁵ In any case, for the reasons stated above, we decline to grant such relief here.¹³⁶

¹³³ We note further, as TVA points out, that although the majority of the projects identified in the Compliance Order were undertaken after 1985 (TVA Response to Initial Brief at 83), section IV.1(h) of the Compliance Order calls for the surrender of allowances equivalent to *all* reductions made pursuant to the Compliance Order. Because EPA Enforcement alleges that unreliable 1985 data may have led to improper allocation, such language in the order would appear to be overbroad in that only the Paradise and Colbert modifications were undertaken during 1985 or before.

 $^{^{134}}$ We note, as discussed above, that section IV.1(e) of the Compliance Order requires that TVA conduct an audit of each of its coal-fired power plants to determine the extent of any additional violations. Once this audit is completed, EPA Enforcement may have a better understanding of the extent of the violations and the need for the reallocation and/or surrender of any SO₂ allowances.

¹³⁵ See, e.g., CAA § 403(f), 42 U.S.C. § 7551b(f) ("Nothing in this subchapter or in any other provision of law shall be construed to limit the authority of the United States to terminate or limit [SO₂ allowances]."); CAA § 113(a)(3), 42 U.S.C. § 7413(a)(3). In addition, we note that 40 C.F.R. part 77 provides procedures whereby owners and operators of units with excess SO₂ emissions are required to offset the amount of such excess emissions. See 40 C.F.R. § 77.3(a). Furthermore, the Region may seek penalties for excess SO₂ emissions in the amount of \$2000 per ton multiplied by an annual adjustment factor. Id. § 77.6(b). We do not decide whether these procedures are or are not applicable in the context of this case.

¹³⁶ Because we conclude that EPA Enforcement has not presented sufficient evidence supporting the inclusion of section IV.1(h) in the Compliance Order, we do not address TVA's assertion that EPA Enforcement lacked the authority to include this provision under section 113 of the CAA, 42 U.S.C. § 7413, and the other related arguments TVA raised in its briefs.

3. Authority to Require an Audit

Section IV.1(e) of the Compliance Order states that TVA shall, under the authority of CAA § 114, 42 U.S.C. § 7414,¹³⁷

provide to EPA an audit of each of its coal-fired power plants that identifies all physical changes made since January 1, 1977 that may have triggered the NSR (both PSD and nonattainment NSR) and NSPS requirements of the Clean Air Act or any applicable state plans.

This request for relief would require TVA to provide certain information for projects conducted from January 1, 1977, through December 31, 1999, "in which any component of an electric utility steam generating unit which has a useful life of more than ten years was replaced, enhanced, redesigned, or otherwise physically altered." The information sought includes the following:

- (i) the cost of the project and where the funds for the project came from (e.g. capital expenditure, plant maintenance budget, etc.);
- (ii) a description of the project activities, including any and all design changes between the existing component and its replacement;
- (iii) the amount of time of the scheduled outage in which the project was carried out;
- (iv) the purpose of the project, including any discussion of why the project is needed (e.g. forced outage rates, reduced capacity, etc.

For the purpose (i) of developing or assisting in the development of any implementation plan under section 7410 or section 7411(d) of this title * * * [or] (ii) of determining whether any person is in violation of any requirement of such a plan * * *

¹³⁷ Section 114(a) states, in pertinent part:

⁽¹⁾ The Administrator may require any person who owns or operates any emission source * * * who the Administrator believes may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter * * * on a one-time, periodic or continuous basis to:

⁽A) establish and maintain such records;

⁽B) make such reports;

⁽C) install, use, and maintain such monitoring equipment, and use such audit procedures, or methods; [and]

⁽G) provide such other information as the Administrator may reasonably require * * *.

- * * *) and what are the anticipated benefits of the project (e.g. life extension of the unit, regained capacity, eliminate derating, etc.);
- (v) the age of the unit and the date of the last time this same project or a similar project was undertaken with respect to that unit or any other units at the facility;
- (vi) whether the project is part of a series of projects at the unit or facility to regain lost generation, increase capacity or extend the life of the unit or facility;
- (vii) the projected future emissions (for NO_x, SO₂, and PM) that will result from the project as would have been calculated by TVA before the project was conducted. The calculated emissions shall include the maximum hourly emission rate as well as the annual emissions increase for NO_x, SO₂, and PM;
- (viii) the actual emissions that occurred at the unit and the facility for the five years after the project was completed or if the project was completed after November 1995, for each year since the project was completed. The actual emissions shall include the maximum hourly emission rate as well as the annual emissions increase for SO₂, NO_x, and PM.; and
- (xi) a conclusion by TVA whether NSR and/or NSPS has been triggered by the physical change based on the information in items (i) through (viii).

Compliance Order § IV.1(e).

TVA asserts that the audit provision is not properly before the Board at this time. TVA Response to Initial Brief at 76. In particular, TVA states that the audit requirement is an information request under CAA § 114, 42 U.S.C. § 7414, and that it is therefore not part of the Compliance Order. Thus, according to TVA, because the Board's jurisdiction in this matter is limited by the Administrator's May 4 Memorandum to conducting proceedings and issuing a decision on reconsideration of the Compliance Order, the Board lacks jurisdiction to consider the audit provision at issue here. TVA Response to Initial Brief at 76-77. TVA further states that the audit provision cannot be made part of the Compliance Order. According to TVA, "[o]nly if TVA refuses to comply with a § 114 information request can it become the subject of a compliance order under section 113(a)(3)." *Id.* at 77.

Examination of the Administrator's Memorandum reveals that the Administrator clearly intended that the Board's proceedings on reconsideration include all

material provisions of the Compliance Order, including the audit requirement. The Administrator delegated to the Board the authority "to conduct appropriate proceedings upon reconsideration of the Order cited above." Administrator's Memorandum at 2. On the first page of her delegation memorandum the Administrator states that the term "Order" refers to the November 3 Administrative Order as well as subsequent revisions. This would include the Fourth Amended Order and Request for Information. Moreover, the Administrator noted that at a December 20, 1999 meeting between TVA and the Regional Administrator, TVA had requested reconsideration of the Order and submitted its Response to the Administrative Order. In that response, TVA objected to EPA's authority under CAA § 113 to order TVA to conduct an audit. Thus, TVA's objection to the audit provision was included in documents forming the basis for the Administrator's Memorandum. We therefore read the Memorandum broadly to include all provisions of the Fourth Amended Order and Request for Information, including the audit requirement.

Further, although TVA is correct that the audit provision constitutes an information requirement, the Compliance Order is styled as an order and request for information. Thus, the title of the order makes clear that it contains both compliance and information requirements. While TVA may be correct that the audit provision could be the subject of a Compliance Order under CAA § 113(a)(3), 42 U.S.C. § 7413(a)(3), should TVA fail to fully comply, we find nothing improper in the Region's decision to combine a compliance order with an information requirement. TVA's assertions in this regard are therefore rejected.

TVA also questions the reasonableness of the audit provision. TVA does not dispute the Region's authority to require information from regulated power plants under CAA § 114(a), 42 U.S.C. § 7414(a). Rather, TVA argues that the audit provision may be overbroad depending on how it is interpreted by the Region. ¹³⁸ In this regard, TVA states that it "reserves the right to object on 'reasonableness' grounds" if the Region determines that the information already provided does not meet the audit requirement. TVA Response to Initial Brief at 80.

While we certainly agree with TVA that a request for information under CAA § 114 must be a reasonable one (CAA § 114(a)(1)(G), 42 U.S.C. § 7414(a)(1)(G)), we have reviewed the above-quoted audit provision and conclude that it satisfies this requirement. The information requested bears directly on whether a violation of the CAA has occurred, and the request appears reasonably

TVA states that on May 22, 2000, it submitted information to the Region satisfying the audit requirement. TVA Response to Initial Brief at 80. To our knowledge, the Region has not responded to TVA's statement regarding the sufficiency of this information. As this issue is not before the Board at this time, we do not reach the question of whether the information provided by TVA satisfies the audit requirement. We would only note that in satisfying the audit requirement, TVA's compliance must be consistent with the Board's interpretations and determinations in this decision.

tailored to elicit that information. That is, sections (i) through (vi) quoted above seek information necessary to determine if any projects were within the scope of the routine maintenance, repair, and replacement exception to the physical change requirement. See 40 C.F.R. § 52.21(b)(2)(iii). Sections (vii) and (viii) seek information on whether changes resulted in any emissions increases. Requiring that TVA provide this information does not strike us as unreasonable, especially considering that the Board has already found numerous other violations of the Act. See supra Parts III.D-G. Further, as far as we can tell from the record before us, TVA has not indicated that it would be unable to comply with the information request, nor has TVA sought additional time to do so. Under these circumstances, TVA's objections to the audit requirement are rejected.¹³⁹

III. CONCLUSION

For the foregoing reasons, we reach the following conclusions.

We conclude that EPA Enforcement has met its burden of establishing that each of the fourteen projects constitutes a physical change under the CAA and applicable regulations and that TVA has not met its burden of establishing that any of the projects fall within the exception for routine maintenance, repair and replacement. In reaching this conclusion we apply the four-factor test advocated by EPA Enforcement and adopted by the Seventh Circuit in its WEPCO decision to determine whether a change falls within the scope of the exception. The fourfactor test is reasonable and consistent with the statute, regulations, and case law. In contrast, we reject TVA's view of the breadth of the exception as it would, in our view, swallow the rule that subjects existing sources to the requirement to install modern pollution controls when physical changes that increase emissions are made to these plants. In addition, we reject TVA's "fair notice" arguments, concluding instead that the Agency's interpretation was "ascertainably certain" from the regulation's text and its context. Moreover, given the magnitude and circumstances of the projects at issue here, TVA reasonably should have been on notice that these projects may not qualify for the routine maintenance, repair and replacement exception. We also conclude that TVA has not shown that EPA has changed its interpretation of the exception.

Findings of Violations That Are Vacated

We vacate the following findings of violation of the Compliance Order on the grounds that such claims have either been abandoned by EPA Enforcement

¹³⁹ TVA has also argued that the audit requirement is not authorized by CAA § 167, 42 U.S.C. § 7477. However, because we conclude that the audit requirement is authorized by section 114(a), we need not address TVA's argument in this regard.

during the course of this proceeding or that EPA Enforcement failed to sustain its burden of proof with respect to whether the physical changes resulted in an emissions increase:

- (1) NSPS violation at Paradise Unit 3. EPA Enforcement has abandoned its claim that the physical changes to Paradise Unit 3 violated the NSPS.
- (2) Emissions violation of the NSPS at Colbert Unit 5. With respect to Colbert Unit 5, EPA Enforcement introduced no evidence as to whether the post-change emissions from Colbert Unit 5 exceeded the NSPS emissions standards of 40 C.F.R. part 60, subpart Da (however, as discussed below EPA Enforcement did demonstrate other NSPS violations at Colbert Unit 5).
- (3) Kentucky minor NSR violations. EPA Enforcement has abandoned its claims that the physical changes made to Paradise Units 1, 2, and 3 and Shawnee Units 1 and 4 required a Kentucky minor NSR permit.
- (4) PSD or nonattainment NSR claims that EPA Enforcement has abandoned regarding NSR permitting for certain pollutants. EPA Enforcement abandoned claims that the changes to the following units result in a significant net emissions increase with respect to the following pollutants:

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Allan Unit 3 — PM

Cumberland Units 1 and 2 — SO<sub>2</sub>

John Sevier Unit 3 — PM

Kingston Unit 6 — PM

Paradise Units 1, 2 and 3 — SO<sub>2</sub> and PM

Shawnee Unit 1 — PM

Shawnee Unit 4 — PM
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Accordingly, we vacate the Compliance Order's statements regarding violations for these pollutants at these units.

(5) PSD or nonattainment NSR violations as to which EPA Enforcement failed to sustain its burden of proof. EPA Enforcement failed to sustain its burden of proof that the changes to the following units result in a significant net emissions increase with respect to the following pollutants:

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Bull Run Unit 1 — PM;
Cumberland Unit 1 — PM;
Cumberland Unit 2 — PM;
John Sevier Unit 3 — NO<sub>x</sub>;
Kingston Unit 8 — PM;
Widows Creek Unit 5 — NO<sub>x</sub>, SO<sub>2</sub>, and PM.
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Accordingly, we vacate the Compliance Order's statements regarding violations for these pollutants at these units.

Findings of Violations That Are Sustained

With respect to the following claims of violation for the identified pollutants at the indicated units, we sustain the Compliance Order's findings of violation of the CAA's PSD and/or nonattainment NSR permitting requirements:¹⁴⁰

	NO _x	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	
Colbert Unit 5	X	X	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		
John Sevier Unit 3		X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	
Paradise Unit 1	X		
Paradise Unit 2	X		
Paradise Unit 3	X		
Shawnee Unit 1	X	X	
Shawnee Unit 4	X	X	

With respect to the following claims of violation for the identified pollutants at the indicated units, we sustain the Compliance Order's findings of violation of the minor NSR permitting requirements of the applicable state SIPs:¹⁴¹

¹⁴⁰ This chart is a reproduction of the Chart No. 2 set forth in Part III.A of this decision, where we provide a more detailed summary of our conclusions.

¹⁴¹ This chart is a reproduction of Chart No. 3 set forth in Part III.A of this decision, where we provide a more detailed summary of our conclusions.

	NO _X	SO ₂	PM
Allen Unit 3	X	X	
Bull Run Unit 1	X	X	X
Cumberland Unit 1	X		
Cumberland Unit 2	X		X
John Sevier Unit 3	X	X	
Kingston Unit 6	X	X	
Kingston Unit 8	X	X	X
Colbert Unit 5	X	X	X
Widows Creek Unit 5	X	X	X

We also sustain the Compliance Order's findings of violation of the NSPS performance testing, record keeping and reporting requirements of 40 C.F.R. part 60, subpart Da at Colbert Unit 5.

Sustained and Vacated Remedy Provisions of Compliance Order

With respect to the Compliance Order's remedies for the violations identified above, we briefly summarize here our conclusions and analysis previously set forth in Part III.G. There, we vacate Compliance Order section IV.1(h) regarding surrender of SO₂ allowances subject to our discussion in Part III.G.2.¹⁴² We sustain the requirements that TVA submit schedules for it to come into compliance with the CAA with respect to the violations sustained by this decision and, more generally, the requirements set forth in sections IV.1(a) to (g) of the Compliance Order. We also specifically sustain the requirements that TVA apply for, and obtain, NSR permits for the units and pollutants as to which we have sustained the findings of violation (Compliance Order section IV.1(d)). With respect to the Compliance Order's statements in section IV.1(a) that SCR shall be the minimum controls for NO_X emissions, as more fully discussed in Part III.G.1, we hold that EPA Enforcement shall be bound by its interpretation of such statements as its settlement position and we further hold determination of what constitutes BACT and LAER must be made on a case-by-case basis, by the applicable permitting authority, consistent with the requirements in effect at the time of the permit ap-

 $^{^{142}}$ As discussed in Part III.G.2 of this decision, if upon completion of its analysis, EPA Enforcement continues to believe that a reallocation and/or surrender of SO_2 allowances is appropriate, EPA Enforcement is not precluded by this order on reconsideration from pursuing that avenue of relief in an appropriate proceeding.

plications. Subject to our discussion in Part III.G.3, we also sustain the portions of the Compliance Order requiring TVA to perform an audit of its coal-fired electrical generating units and remedy violations identified by the audit (Compliance Order sections IV.1(e), (f), (g)).

So ordered.

TENNESSEE VALLEY AUTHORITY APPENDIX A

APPENDIX A PROJECT-BY-PROJECT FINDINGS REGARDING THE ROUTINE MAINTENANCE EXCEPTION

The following is a detailed discussion of our findings regarding whether the individual projects undertaken by TVA fall within the routine maintenance, repair and replacement exception under NSR.

A. Allen Plant Unit 3

The Allen Plant is located in Shelby County, Tennessee and began operations in 1959. The project under review involved a Fall 1992 scheduled outage² in which TVA replaced several boiler components, including the existing horizontal reheater with a redesigned reheater. EPA Enforcement Ex. 279, at 17 (Hekking's pre-filed testimony). In reviewing the record, we find several facts significant in applying the four factor test.

1. Nature and Extent

TVA began planning this project in 1990. Given the project's significance, approval was required from TVA's Board of Directors. The project, which was managed by TVA's central office instead of the plant's maintenance department, was completed in 1993. During the actual implementation of the project, TVA shut down the unit for three months. EPA Enforcement Ex. 273. In WEPCO, the court found the length of the shutdown to bear on the magnitude of the project. WEPCO, 893 F.2d. at 911. Although the shutdown time here is shorter than that in WEPCO, we nevertheless find it to be significant, given that scheduled maintenance outages are typically limited to four weeks. See Tr. at 225. The extent of this project is illustrated by Mr. Hekking's testimony, in which he states:

The entire boiler was stripped of external lagging and insulation to make access for the structural modifications required for the conversion from positive furnace pressure to negative. An opening was cut in the furnace sidewall and a platform constructed for the removal and

¹ Originally, Memphis Light, Gas and Water Division ran the plant. In July of 1965, TVA began running the plant, and, in 1985, TVA became the sole owner of the plant.

² A scheduled outage is a planned shutdown as distinguished from a forced outage which occurs when components or portions of components fail causing the unit to shutdown unexpectedly. Mr. Randolph testified at the hearing that the length of time a forced outage would shut down a unit could range from hours to five days. Tr. at 111. According to Mr. Hekking, a scheduled outage, which typically occurred once every eighteen months, generally lasted four weeks. Tr. at 225.

reinstallation of the reheater elements. A railroad track was built from the platform into the building for the movement of the elements back and forth. The building's structural steel was reinforced to support the additional weight. A monorail system was constructed inside the boiler to move the elements in and out, onto a trolley built for the railroad track to run between the boiler and the outside platform. The old elements were cut loose from the boiler, loaded onto the trolley, and rolled out to the platform where a mobile crane picked them up and set them onto trucks for hauling to a storage area. The new elements were brought into the boiler in the reverse manner. A total of 540 reheater elements, arranged in six banks, or sections, were removed and re-designed replacements were installed.

EPA Enforcement Ex. 279, at 17 (Hekking's pre-filed testimony). TVA replaced approximately 44% of the 234,219 square feet of total boiler surface in this project. TVA Ex. 4, at 31 (Golden's pre-filed testimony).

2. Purpose

The purpose of this project is described in TVA's work order, which cites the elimination of current failures and deratings resulting from slagging as among the purposes for this project. EPA Enforcement Ex. 51. TVA further explains the project in its records that the project would address tube failures at a reheater that was thirty years old in 1990 and thus approaching the end of its productive life. EPA Enforcement Ex. 53. Indeed, TVA's work order explains that the tube failures indicate "an end of life failure mode." EPA Enforcement Ex. 63. Thus, this project was intended to extend the life of the unit.

Moreover, the construction project was funded through the central office's capital budget.³ As explained in some detail *supra* Part III.C of this decision, under TVA's capitalization policy, this classification shows TVA's intent to improve the unit, not merely to maintain it.

3. Frequency

The record indicates that this project was the only one of its kind in the unit's lifetime. EPA Enforcement Ex. 279, at 17 (Hekking's pre-filed testimony). TVA does not dispute this fact; however, it emphasizes that similar projects had occurred with some frequency within TVA and in the utility industry generally. See TVA Ex. 4, at 10 (Golden's pre-filed testimony). Specifically, TVA argues that repair or replacement of damaged reheater tubing either when it fails or prior to its failure was a "utility practice * * * in place long before the New Source

³ This fact is also significant in examining the cost element of the four-factor test.

Review regulations were contemplated. Since 1977, TVA has performed ninety-three reheater replacement projects (only forty-nine of TVA's fifty-nine units have reheaters)." *Id.* at 31. Moreover, TVA argues that when compared to the cost and time shutdown of the project under review in *WEPCO* (the *WEPCO* project), the Allen Unit 3 project is routine.

As we noted earlier in Part III.C.3 of this decision, we think the relevant inquiry regarding frequency focuses most importantly on the significance of the project in the life of the unit in question, and this evaluation can be informed by the frequency of the activity at other units within the industry. This point was emphasized by the *WEPCO* court when it stated that "the renovation work items * * are those that would normally occur only once in a *unit's* expected life cycle." *WEPCO*, 893 F.2d at 912 (emphasis added). TVA's evidence does not establish that reheater replacements were routine within the life of a unit like Allen Unit 3. Rather, they are uncommon events in the life of such a unit. Moreover, we have previously rejected the notion that the mere fact that others in the industry have done this type of replacement makes it "routine." *See supra* Part III.C.3.

4. Cost

TVA's Fossil and Hydro Modifications Division at the central office performed this project at an approximate cost of \$10.78 million.⁴ Mr. Hekking testified that the project could not have been funded through the plant's O & M budget because the entire O & M budget for Allen's three units combined was less than the project's cost.⁵See Tr. at 245.

As discussed above, TVA argues, generally, that EPA Enforcement's comparison of the O & M budget of the plant to the cost of the project is misleading because the O & M budgets do not include the "entire spectrum of routine maintenance, repair and replacement." TVA asserts that, "yearly plant maintenance budgets are intended to cover day-to-day minor maintenance activities that the plant maintenance staff conducts, but they do not cover common maintenance, repair and replacement activity that TVA has found more cost-effective to centralize * * *." TVA Post-Hearing Brief at 34-35. This statement notwithstanding, we find the fact that the individual plant's O & M budget was less than the cost of many of these projects is quite relevant where it shows the extensive nature of the project in relation to daily and "running maintenance" handled by the plant's maintenance department.

⁴ The parties have different cost figures for the project. However, both parties agree that the differences are not that great and are, therefore, not relevant. Tr. at 338-40. We will use EPA's figures, which were obtained from TVA records.

⁵ Mr. Hekking estimated the O & M budget for the Allen plant in the early 1990s to be \$9.5 million. Tr. at 245.

On balance, we find that, considering the evidence in the record and applying the four factor test, TVA has not established that its project at the Allen Plant Unit 3 comes within the scope of the routine maintenance exception. Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for this or a like project that would support a finding that this project constituted routine maintenance, repair and replacement.

B. Paradise Plant Units 1, 2, and 3

The Paradise plant is located in Drakesboro, Kentucky. Units 1 and 2 began commercial operations in 1963, and Unit 3 began in 1970. In 1985,⁶ TVA performed a series of replacements at the Paradise plant's Units 1, 2, and 3. The significant facts from the record are highlighted below using the four factor test as a framework.

1. Nature and Extent

The work was essentially the same at all three units. It included the replacement of all cyclone burners attached to each boiler and the replacement of the lower furnace walls, floor and headers. EPA Enforcement Ex. 273; EPA Enforcement Ex. 279, at 40-42 (Hekking's pre-filed testimony); TVA Ex. 4, at 23-26 (Golden's pre-filed testimony).

Through these projects, TVA replaced all fourteen cyclone burners at each of Units 1 and 2 and replaced all twenty-three cyclone burners at Unit 3. In addition, TVA cut out and replaced the waterwall below 465 feet, including the lower headers and floor at Unit 1. TVA performed the same work at Unit 2. At Unit 3, in addition to the twenty-three cyclones, TVA replaced the waterwalls between 418 feet to 501 feet. TVA Ex. 4, at 23-25 (Golden's pre-filed testimony); EPA Enforcement Ex. 279, at 42 (Hekking's pre-filed testimony).

The magnitude of the work at each of these units was significant. Indeed, TVA had to construct monorails at the front and rear walls for lifting and positioning the cyclones at each unit. EPA Enforcement Ex. 279, at 43 (Hekking's pre-filed testimony). TVA installed a trolley system to transport the cyclones in and out of the building, and TVA constructed rigging inside the furnace to assist in attaching the wall panels and floor panels. *Id*.

After approval from the Board of Directors and after years of planning, the central office's Fossil and Hydro Power Division performed work on these units

⁶ The work at Unit 1 began in March of 1985; the work at Unit 2 began in November of 1985; and the work at Unit 3 began in October of 1984. *See* TVA Ex. 4, at 23-26 (Golden's pre-filed testimony).

sequentially.⁷ TVA implemented the work at Unit 3 first, beginning in the Fall of 1984 and requiring the unit to be shut down for six months. It then worked on Unit 1, shutting it down for approximately 6.5 months beginning in March of 1985. Finally, TVA performed the work on Unit 2 beginning in November of 1985 and lasting 4.5 months. In each case, the units were shut down for periods well beyond the four weeks typical of scheduled maintenance outages.

The work at Unit 1 and 2 required the replacement of approximately 18.5% of the total tubing in the boiler. TVA Ex. 4, at 23, 25 (Golden's pre-filed testimony). TVA replaced approximately 19.4% of the total tubing in Unit 3's boiler. *Id.* at 26.

2. Purpose

The central office's Fossil and Hydro Power Division recommended these projects at all three units in order to increase each unit's availability and reliability by decreasing the number of forced outages, as well as to extend the life of these units by twenty years. See EPA Enforcement Exs. 3, 4, 6, 9. Apparently, TVA had in the past repaired and replaced individual tubes in the waterwalls, floors and the cyclones, but the forced outages continued to increase. EPA Enforcement Ex. 279, at 40 (Hekking's pre-filed testimony); EPA Enforcement Ex. 16. Additionally, TVA classified these projects as capital projects and thus intended these projects to improve the units, not merely to maintain their present condition.

3. Frequency

The work performed on these units was the first and only of its magnitude at these units. EPA Enforcement Ex. 279, at 43 (Hekking's pre-filed testimony). TVA points out that cyclone replacements had been done within the industry and at TVA in the past. TVA Ex. 4, at 24 (Golden's pre-filed testimony). TVA's proof, however, falls short of suggesting that this work is common in the lives of individual units of this kind.

4. Cost

TVA's central office performed these projects at an approximate cost of

⁷ A factual inconsistency exists between TVA and EPA Enforcement regarding the actual dates of each units' renovation. However, the length of time is substantially the same under either party's facts. See TVA Ex. 4 (Golden's pre-filed testimony); EPA Enforcement Ex. 279 (Hekking's pre-filed testimony).

\$16.3 million for Unit 1,8 \$15.79 million for Unit 2, and \$29.44 million for Unit 3. See EPA Enforcement Ex. 273. Additionally, given the size of the Paradise plant, it is probable that, similar to the Allen Plant, Paradise's O & M budget could not have supported such projects while meeting other maintenance needs.9

On the whole, TVA has not established that these projects fall within the "routine" exclusion when the four factor test is applied to the facts. Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for these or like projects that would support a finding that these projects constituted routine maintenance, repair and replacement.

C. Bull Run Unit 1

The Bull Run Plant is located in Anderson County, Tennessee and began operations in 1967. Unit 1 began to experience tube leaks in its economizer section that increased in frequency and duration. Additionally, there were tube leaks in the secondary superheater tubing, caused by deterioration of the tube material from twenty years of service. In applying the four factor test, we, based on our review of the record, find several facts significant to each factor.

1. Nature and Extent

The project, which required approval by TVA's Board of Directors and was managed by TVA's central office, required the removal and replacement of over sixty-seven miles of two-inch diameter tubing from the economizers in both furnaces at Unit 1. EPA Enforcement Ex. 279, at 21 (Hekking's pre-filed testimony). In replacing the secondary superheater in both furnaces, TVA removed and replaced over 58,000 feet of tubing. EPA Enforcement Ex. 73; EPA Enforcement Ex. 279, at 21 (Hekking's pre-filed testimony). Four separate sections of the unit were involved in this project — the economizer in the lower rear section of the furnace and the secondary superheater in the upper convection section, for each of the two furnaces. EPA Enforcement Ex. 279, at 21 (Hekking's pre-filed testimony). After years of planning, the project was completed in 1988. In order to implement the project the unit remained shut down for a three-month time frame, beyond the four weeks typical of scheduled maintenance outages. TVA replaced about 26.5% of the total tubing in the boiler. TVA Ex. 4, at 20, 22 (Golden's pre-filed testimony).

⁸ At the hearing Mr. Majoros compared the cost of the project to the cost of the original installation of the unit in real dollars. The cost of the project was approximately a third of the original installation cost. *See* Tr. at 357-58.

⁹ Although the only plant-specific O & M budget referenced in the record is for the Allen Plant in the early 1990s, we assume both that it is representative of O & M budgets for TVA plants of that size and a useful benchmark for estimating O & M budgets at other TVA plants. See Tr. at 245.

2. Purpose

TVA concluded that the leaks in the tubing would escalate if left unaddressed. EPA Enforcement Ex. 72. In 1986, the Fossil and Hydro Power Division recommended to TVA management the replacement of the economizer and the secondary superheater components of the unit to "reduce the number of forced outages, increase the availability and reliability of the unit, and [to] extend the life of this section of the boiler by approximately 20 years." EPA Enforcement Ex. 72; see also EPA Enforcement Exs. 73, 74. Like all projects at issue in this case, TVA classified this project as a capital project; thus, TVA intended the project to improve the condition of the unit, not merely restore and maintain it.

3. Frequency

This project was the only one of its kind in the unit's history. EPA Enforcement Ex. 279, at 20 (Hekking's pre-filed testimony). TVA raises very similar arguments for its defense of routine maintenance, repair and replacement at this unit as it did for the other projects. TVA placed into the record testimony regarding the frequency at which similar projects have occurred within TVA's plants and throughout the industry. Nowhere did it establish, however, that those replacements took place other than rarely in the lifetime of a unit like this one.

4. Cost

The total capital cost of the project (including replacement of both economizers and secondary superheaters) was approximately \$8.3 million. EPA Enforcement Ex. 279, at 23 (Hekking's pre-filed testimony). Additionally, as discussed *supra* Part III.C of this decision, it is probable that Bull Run's O & M budget could not have supported such a project while meeting other maintenance needs.

Under the four-factor test, we look at more than just frequency of one-time facility events in the industry to determine whether a project falls within the routine maintenance exception to the NSR regulations. Here, TVA did not establish that the Bull Run Plant Unit 1 project falls within the exception for "routine maintenance, repair and replacement." Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for this or a like project that would support a finding that this project constituted routine maintenance, repair and replacement.

D. Colbert Plant Unit 5

The Colbert Plant is located in Tuscumbia, Alabama. The plant began operating in 1965. In 1983, TVA undertook a major overhaul of Colbert Unit 5. The

significant facts from the record are highlighted below using the four-factor test as a framework.

1. Nature and Extent

The project involved replacement of the waterwalls and horizontal reheater, modification of the startup system, modification of the superheater by adding wingwalls in the furnace, replacement of gas proportioning dampers, replacement of the windbox, redesigning and replacement of the control system, and addition of a balanced draft conversion system.¹⁰ Indeed, as Mr. Golden testified, "[i]t was the largest unit rehabilitation project that TVA had ever undertaken." Tr. at 743. Although TVA completed the renovations in 1983, it began planning the project in the late 1970s. The central office planned and, after approval by the Board of Directors, performed the project during a thirteen-month shutdown, substantially beyond the four-week period typical of scheduled maintenance outages.

2. Purpose

The record reflects that TVA had determined that by changing from pressurized to balanced draft firing, it could significantly increase the unit's annual output, which would also reduce the number of forced outages and deratings resulting from the gas leakage from the unit. See EPA Enforcement Ex. 44; EPA Enforcement Ex. 279, at 26 (Hekking's pre-filed testimony). Further, the record establishes that the project was undertaken because of the boiler's deteriorated state and the control system's inadequacy. EPA Enforcement Ex. 36. TVA stated in its proposed project authorization:

Attached is a proposed project authorization for \$46,848,650 to rehabilitate and modify the Colbert unit 5 boiler, turbine, and control system. The outage rates on this unit continue to increase to intolerable levels because of the combined effect of several inadequate features associated with this prototype equipment. This work is expected to show a significant improvement in reliability and load-carrying capability and extend the useful life of the unit for 20 years.

EPA Enforcement Ex. 27. Further, TVA's classification of this project as a capital project shows that TVA intended to improve the condition of the unit, not merely maintain it.

¹⁰ EPA Enforcement notes that the conversion of the boiler to a balanced draft system, which uses negative pressure, represented a fundamental change in the boiler's control of the combustion process, whereas prior to the construction, the system used positive pressure. EPA Enforcement Ex. 279, at 26 (Hekking's pre-filed testimony).

3. Frequency

TVA implemented this project to fix a unit that was not working as designed. Accordingly, the project included modifications on a major scale and resulted in a fundamental change in the manner Unit 5 was operated. It thus seems self-evident that the project was extraordinary in nature and scope and was the kind of project that would only rarely be undertaken in the lives of most units of this kind. EPA Enforcement Ex. 279, at 27 (Hekking's pre-filed testimony).

4. Cost

TVA spent approximately \$57.1 million on this construction project, which required over a year to complete. EPA Enforcement Ex. 204. As with the other projects, the funding for the project came from TVA's capital budget. The cost of the work — \$57.1 million — certainly was substantial in absolute terms and required approval by TVA's Board of Directors. See EPA Enforcement Ex. 279, at 15 (Hekking's pre-filed testimony). Moreover, it is not difficult to conclude that Colbert's O & M budget could not have been adequate for the project, given its high costs.

In this instance, TVA argues that Unit 5 was a prototype and, therefore, subject to problems. See TVA Ex. 4, at 29 (Golden's pre-filed testimony). TVA argues that it is common in its industry for prototype units to require corrective action. Additionally, Mr. Golden testified that "it would have been unprecedented in the industry then, and in the industry now to walk away from a coal-fired plant that early in its life." Id. TVA points out that the unit was only seventeen years old when construction activities began. Additionally, TVA points out that each of the components replaced at Unit 5 have been replaced on a frequent basis within TVA. TVA again concludes that the Colbert Unit 5 project was routine when compared to the WEPCO project, which extended the useful life of the units in question. Moreover, TVA argues that Colbert's cost in comparison to WEPCO's was significantly less. 13

Although TVA appears not to have implemented these projects at Unit 5 solely to extend the useful life of the seventeen-year-old unit, many other facts persuade us that the rehabilitation of Unit 5 was nonetheless not "routine mainte-

Mr. Golden's testimony misses the point. NSR regulations would not prohibit the work TVA performed at Unit 5 but rather require TVA to obtain a permit before constructing.

¹² In Golden's pre-filed testimony, TVA does not address whether TVA or anyone in the industry had ever implemented a similar rehabilitation in the aggregate or how frequently any such replacement of individual components were in the life of the individual units.

¹³ TVA cites comparison figures between Colbert Unit 5 and *WEPCO*'s projects as \$103.85 per kilowatt ("kw") versus \$220/kw, respectively.

nance, repair and replacement." The Board in particular finds the magnitude of the renovation, the length of time required to plan and implement the project, and the duration of the outage caused by the work at Unit 5 to be significant facts that cut against considering this construction work to be "routine." Indeed, it looks anything but routine. Moreover, since the project's purposes included increasing the unit's reliability, increasing its load-carrying capability by decreasing the number of outages experienced at the unit, and extending the life of the unit, this too shows the project was not routine and went beyond mere restoration of the unit to its former condition prior to the work. TVA's use of the capital budget for this project also reinforces the conclusion that TVA intended this work would leave the unit in an improved condition. 14 See EPA Enforcement Ex. 152.

On balance, although we recognize there are differences between this project and the others at issue in this case, TVA has not established that the work at Colbert Unit 5 to be "routine, maintenance, repair and replacement." Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for this or a like project that would support a finding that this project constituted routine maintenance, repair and replacement.

E. Cumberland Plant Units 1 and 2

The Cumberland Plant is located near Cumberland City, Tennessee. The units involved in this case, Units 1 and 2, began operating in 1973. This plant is the newest and largest plant in TVA's system. The record reveals several significant facts regarding these projects.

1. Nature and Extent

As detailed in TVA's scoping specification memo for the Cumberland plant, prior to the renovations both units were experiencing forced outages due to the need to repair secondary superheater tube leaks the unit had been experiencing. EPA Enforcement Ex. 111. In 1988, TVA's central office recommended the complete replacement of both secondary superheater outlet headers and 1,460 terminal tubes, asbestos insulation removal, insulation installation, and structural steel reinforcement for Unit 1. EPA Enforcement Ex. 81. In 1996, after TVA's Board of Directors approved the project, TVA's central office managed the work at Unit 1. EPA Enforcement Ex. 273.

¹⁴ The work TVA did at Unit 5 not only replaced components but improved the unit. Examples of these improvements to the unit include: the addition of wingwalls in the furnace, the redesign of the windbox to improve air distribution, and the conversion to a balanced draft system. *See* EPA Enforcement Ex. 22.

Regarding Unit 2, in 1994, after TVA's Board of Directors approved the project, TVA's central office managed the replacement and redesign of the secondary superheater outlet headers, the replacement of the secondary superheater pendant elements and the replacement of the lower slope and lower waterwalls. *See* EPA Enforcement Exs. 103, 105, 273. The headers alone were over 110-feet long and "were massive pieces of metal with intricate machine work for the more than 700 tube stub holes, outlet steam piping, and other attachments," weighing over eighty tons each. EPA Enforcement Ex. 279, at 31-32 (Hekking's pre-filed testimony).

The projects at both units took three months to complete once on-site activity began and several years of planning¹⁵ prior to implementation. Again, the three-month shutdown went well beyond the four weeks typical for scheduled maintenance outages. EPA Enforcement Ex. 273.

2. Purpose

TVA explained that the work was required for Unit 1 because the secondary superheater headers had been prone to thermal fatigue cracking and this cracking decreased the unit's availability to generate power. *Id.* "In their present condition, these headers cannot be safely or reliably operated for more than 3 years." *Id.* Thus, the purpose of these projects was to eliminate forced outages, increase capacity at both units and extend the life of the unit. In addition, TVA replaced the secondary superheater pendant elements and replaced the lower slope and lower waterwalls at Unit 1. EPA Enforcement Ex. 279, at 31-32 (Hekking's pre-filed testimony); EPA Enforcement Ex. 273. TVA funded both projects as capital projects, intending both projects to improve, rather than simply maintain, each unit's condition.

3. Frequency

The two projects at Unit 1 and Unit 2, respectively, replaced at substantial cost a number of key boiler components that had never been replaced on either unit.

TVA contends that utilities commonly replace components that "pose a threat to employee safety or the unit's ability to reliably generate electricity." TVA Ex. 4, at 35 (Golden's pre-filed testimony). The fact that this may have been one of their purposes does not, by itself, determine the outcome of whether the work

TVA took eight years to plan the project at Unit 1 and six years to plan the project at Unit 2. See EPA Enforcement Ex. 80.

was "routine." TVA does acknowledge that replacement of superheater headers is done less frequently, but states that "TVA has historically replaced headers when conditions justify such replacements." *Id.* TVA's evidence falls short of demonstrating that such replacements are anything other than uncommon events within the life of units like Cumberland Units 1 and 2.

4. Cost

The work performed at Unit 1 was in excess of \$22 million, and TVA spent over \$18 million on the project at Unit 2. It is probable that the O & M budget for this plant would not have been sufficient to finance these projects and meet other maintenance needs.

Based on the totality of the facts, the Board finds that TVA has not met its burden to establish that the projects at Unit 1 and 2, in 1996 and 1994, respectively, were "routine maintenance, repair and replacement." Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for these or like projects that would support a finding that these projects constituted routine maintenance, repair and replacement.

F. John Sevier Plant Unit 3

The John Sevier Plant is located in Hawkins County, Tennessee. Unit 3 at the plant began operations in 1956 and has a rated capacity of 135 MW. In the 1980s, Unit 3 began to experience problems in the waterwalls due to extensive tube failures, and TVA accordingly initiated work orders for the Unit 3 work in the mid-1980s. In reviewing the record, the Board found several facts significant in its application of the four factor test.

1. Nature and Extent

The central office's Fossil and Hydro Power Division recommended to its management that TVA replace the complete boiler set of superheater platen elements, replace eight burner tube panels in both furnaces, and replace all waterwall tubes in portions of the front, rear, and sidewalls. TVA's project included replacing the waterwall tubes on the rearwall from 1097 feet to 1164 feet; on the sidewalls and frontwall in both furnaces up to 1,197 feet. PA Enforcement Ex. 67.

We do not doubt that components at older units may have safety and reliability issues, but in our view this does not alone establish whether or not the replacement was "routine."

¹⁷ There is an apparent inconsistency in the record on these facts. In Golden's testimony, he states that sixty-seven feet of the rear waterwall was replaced and that 100 feet of the side and front waterwalls was replaced. See TVA Ex. 4 (Golden's pre-filed testimony). The inconsistency may be Continued

The boiler construction section at TVA's central office was responsible for the project's planning and implementation. After its Board of Directors approved the project and years of planning, TVA initiated on-site activities in 1986 and required the unit to shut down for 2.5 months in order to replace the waterwalls, beyond the four weeks typical of scheduled maintenance outages. The work performed at this unit replaced approximately 8% of the tubing in the entire boiler. TVA Ex. 4, at 12-14 (Golden's pre-filed testimony).

2. Purpose

TVA undertook this work in order to extend the life of the unit by approximately twenty years and to improve its reliability. *See* EPA Enforcement Exs. 65-67. Indeed, TVA's classification of the project as a capital project shows TVA's intent to improve the unit, not merely to maintain it.

3. Frequency

This project was the first time in the unit's lifetime that these components had been replaced. TVA argues that the project constituted routine maintenance, repair and replacement because replacement of damaged waterwalls is common practice within the utility industry.¹⁸ TVA Ex. 4, at 12 (Golden's pre-filed testimony). TVA's evidence falls short, however, of showing that such replacements are anything but rare in the life of a unit like Unit 3.

4. Cost

The project was classified as a capital project, costing TVA approximately \$3.94 million to complete. EPA Enforcement Ex. 279, at 35 (Hekking's pre-filed testimony). Again, given the size of this plant and the cost of this project, it is probable that the O & M budget for the plant would not have been sufficient to finance this project while meeting other maintenance needs.

Based on these facts, the Board finds that TVA has not met its burden of establishing that the 1986 project at the John Sevier Plant Unit 3, based on all the evidence in the record, constitutes "routine maintenance, repair and replacement."

⁽continued)

explained by TVA's separation of the project into several projects. See id. at 12-14. The Board will rely on TVA's work order as the accurate description of the project. See EPA Enforcement Ex. 67.

¹⁸ Further, Golden states, "A survey of maintenance practices of other coal-burning electric utility units, representing more than 20% of the total electricity generation capability in the United States, revealed that of a population sample of 219 utility boilers, 174 waterwall replacement projects had been performed since 1977." TVA Ex. 4, at 12 (Golden's pre-filed testimony). This testimony does not, however, establish that these replacements were common in the life of any particular unit, which, as noted above, is an important aspect of the analysis.

Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for this or a like project that would support a finding that this project constituted routine maintenance, repair and replacement.

G. Kingston Plant Units 6 and 8

The Kingston Fossil Plant is located in Roane County, Tennessee. The plant has nine generating units, two of which are at issue in the present matter — Units 6 and 8. Both units began operations in 1955. The renovations at issue involve the replacement of key components at Units 6 and 8 in the Spring and Fall of 1989, respectively.

1. Nature and Extent

After gaining TVA's Board of Directors approval, TVA's central office performed essentially the same work at both units. The work included replacing all reheater and superheater intermediate pendant elements and the lower waterwalls of the superheater and reheater furnaces. See EPA Enforcement Ex. 279, at 36-37 (Hekking's pre-filed testimony); TVA Ex. 4, at 15-19 (Golden's pre-filed testimony). TVA's central office began planning these projects in 1987 at the latest. See EPA Enforcement Exs. 122, 123, 126. TVA shut down Unit 6 for approximately two months to perform this project and shut down Unit 8 for a three-month period, see EPA Enforcement Ex. 273, thus going beyond the four weeks typical of scheduled maintenance outages.

The work on Unit 6 for the replacement of the reheater and superheater intermediate pendent elements involved replacement of 12,855 square feet of surface area, approximately 9% of the total superheater and reheat surface in the boiler. TVA Ex. 4, at 15 (Golden's pre-filed testimony). The work on the lower waterwalls at Unit 6 replaced approximately 5% of the 70,600 square feet of waterwall surface. *Id.* at 17. TVA's replacement of the superheater crossover tubes at Unit 6 represented less than 3% of the total amount of tubing in the unit. *Id.* at 18. And at Unit 8 the work involving the reheater and superheater required the replacement of approximately 9% of the total superheater and reheater surface at the unit. *Id.* at 19.

2. Purpose

TVA's records show that the purpose of these projects was to replace components that "have operated beyond their designed life and have deteriorated because of long-term overheating causing failure due to creep." EPA Enforcement Ex. 126. TVA justified the cost of these projects because the replacement would increase the reliability and availability of the units. See EPA Enforcement Exs. 122, 123, 126. In its 1986 work order for Unit 8's superheater replacement, TVA stated that the replacement of the superheater elements would "extend the life of

this portion of the boiler by approximately 20 years." EPA Enforcement Ex. 126. Thus, TVA classified these projects as capital projects, which under TVA's own policy were intended to improve the condition of the units, not merely maintain them.

3. Frequency

The record indicates that these projects at Units 6 and 8 were the first replacements of this magnitude for these components, and TVA offered no evidence that such replacements have since occurred at those units. TVA had performed smaller less-extensive replacements at these components in the past, but this does not diminish the significance of the projects under review.

TVA argues that these projects are routine because they are commonly done in TVA's system and the utility industry, generally. TVA Ex. 4, at 15-19 (Golden's pre-filed testimony). As we have said, the fact that others in the industry have done similar projects does not alone assist in determining whether the project falls within the routine maintenance exception. TVA's evidence does not demonstrate that such replacements are anything other than uncommon events within the life of units like Units 6 and 8.

4. Cost

TVA's Fossil and Hydro Modifications Division at the central office performed these projects at an approximate capital cost of \$2.6 million for Unit 6 and \$2.9 million for Unit 8. It is probable that the O & M funds available for these units would have been insufficient to finance this work while meeting other maintenance needs. Again, TVA compares the separate replacement costs at each of Units 6 and 8 with WEPCO's complete cost and claims that TVA's separate replacements were substantially less that the entire cost of WEPCO's modification. TVA Ex. 4, at 15-19 (Golden's pre-filed testimony). The determination that a project is nonroutine does not require a mere cost comparison with WEPCO; rather, a case-by-case determination using the four-factor test is required.

After reviewing the record on these two units, the Board concludes that, based on the facts as a whole, TVA has not met its burden of establishing that the projects performed at Units 6 and 8 were "routine." Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for these or like projects that would support a finding that these projects constituted routine maintenance, repair and replacement.

H. Shawnee Plant Units 1 and 4

The Shawnee Plant is located in McCracken County, Kentucky. In 1953, Units 1 and 4 began commercial operations. The projects involved in this matter

were carried out in the Fall of 1989 and the Spring of 1990 at Units 1 and 4, respectively. The Board finds that following facts from the record to be significant.

1. Nature and Extent

TVA replaced the following items at each unit: "the secondary and reheat superheater pendant and crossover elements including header stubs." EPA Enforcement Exs. 133, 136. The planning required several years to complete. *Id.* These projects were also approved by TVA's Board of Directors and were managed by TVA's central office. TVA funded these projects, like all others at issue, through the capital budget. During the actual implementation of the project at Unit 1, TVA shut down Unit 1 for three months. EPA Enforcement Ex. 134. TVA completed the work at Unit 4 in two months. EPA Enforcement Ex. 137. Both of these projects required a shutdown beyond that of the typical scheduled maintenance outage of four weeks. Additionally, these projects required the replacement of over 132,612 feet of tubing at each unit and represented approximately 37% replacement of total tubing at each unit. TVA Ex. 4, at 32 and 33 (Golden's prefiled testimony).

2. Purpose

The central office recommended the projects because inspections of these components had revealed that the tubing was badly deteriorated and that, if not replaced, the rate of tube failures would increase. Thus, these projects were implemented to reduce the number of forced outages at the unit and prevent the continuing increase of those outages. EPA Enforcement Exs. 133, 136. These projects also extended the life of the units. EPA Enforcement Ex. 279, at 46 (Hekking's pre-filed testimony). TVA's classification of the projects as capital projects, further reinforces that TVA intended these projects to improve the condition of the units, not only to maintain them.

3. Frequency

Similar projects had never been performed on these units in their thirty-six years of operation. EPA Enforcement Ex. 279, at 46 (Hekking's pre-filed testimony). Again, TVA argues that replacements of this kind were commonly performed at TVA and industry-wide. Thus, TVA concludes, the projects at Units 1 and 4 were routine. However, TVA has offered no evidence that similar improvements are anything other than rare in the life of units of this kind, a factor that we find more instructive.

4. Cost

TVA implemented these projects at an approximate capital cost of \$4.5 million for Unit 1¹⁹ and \$5 million for Unit 4. See EPA Enforcement Ex. 279, at 46 (Hekking's pre-filed testimony); EPA Enforcement Ex. 273. Given the size of these units and the cost of these projects, it is probable that the plant's O & M budget would have been insufficient to finance these projects while meeting other maintenance needs.

Again, based on the facts in the record, the Board concludes that TVA has not met its burden to establish that the projects TVA undertook at the Shawnee Plant Units 1 and 4 projects were "routine." Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for these or like projects that would support a finding that these projects constituted routine maintenance, repair and replacement.

I. Widows Creek Plant Unit 5

TVA's Widows Creek Plant is located in Jackson County, Alabama. The plant began commercial operations in 1952. However, Unit 5 did not begin operating until 1954. The final project in this case involves a Fall 1989 scheduled outage at this unit.

1. Nature and Extent

TVA replaced all of the secondary superheater pendant elements, reheater elements, and crossover elements. Additionally, TVA redesigned the tubing to use better materials. See EPA Enforcement Ex. 279, at 47-50 (Hekking's pre-filed testimony); TVA Ex. 4, at 32 (Golden's pre-filed testimony); EPA Enforcement Ex. 46. TVA took several years to plan the project at Unit 5, and, after TVA's Board of Directors' approval, took approximately four months to complete the work, significantly longer than the four weeks required for typical schedule maintenance outages. EPA Enforcement Exs. 46-47. The work, managed by TVA's central office, required replacement of approximately 43.5% of the total feet of tubing in the boiler. TVA Ex. 4, at 34 (Golden's pre-filed testimony).

¹⁹ Mr. Majoros compared the cost of the project at Unit 1 with the cost of the original installation of the unit in real dollars and found the project represented approximately 45% of the original installation cost. *See* Tr. at 362.

²⁰ Golden submitted testimony that TVA implemented the project in a little over two months (October 2, 1989 to December 18, 1989); however, TVA's own completion report for the project indicates that construction began in September 1989 and finished in January 1990. *See* TVA Ex. 4, at 34 (Golden's pre-filed testimony); EPA Enforcement Ex. 47.

2. Purpose

TVA's work order for Unit 5 indicates that the project would extend the life of the unit: "the existing tubes are failing because of creep damage experienced while operating at high-temperatures. This indicates that these tubes have reached the end of life." EPA Enforcement Ex. 46. As with all the other projects previously discussed, TVA classified this project as a capital project, thus intending the project to improve the condition of the unit, not merely to maintain it.

3. Frequency

The work was the first and only replacement of the components in the lifetime of the unit. TVA argues, as it has regarding all of these projects, that the project at Unit 5 must be characterized as routine because many similar projects have been performed by TVA, as well as by others in the utility industry. For the reasons already discussed at length, we reject this argument again because it ignores other relevant facts that must be reviewed in determining whether a project falls within the routine maintenance repair and replacement exception. TVA has not, for example, offered any evidence that similar improvements have been made to this unit prior to the project or since or that such improvements are anything other than uncommon in the lives of units of this kind.

4. Cost

TVA performed this project at an approximate capital cost of \$4.13 million. Given the cost associated with this project, it is probable that the O & M funds for this plant would not have been sufficient to finance this project while meeting other maintenance needs.

On the whole, TVA has not met its burden of establishing that this project was "routine maintenance, repair and replacement." Notably, TVA cites to no applicability determination issued by EPA or the relevant state authority for this or a like project that would support a finding that this project constituted routine maintenance, repair and replacement.

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB	 Judge Bernard A. Friedman Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.)))
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)))
Defendants.))

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 7



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY WASHINGTON, D.C. 20460

JUN 1 7 1993

OFFICE OF AIR AND RADIATION

MEMORANDUM

SUBJECT: Applicability of New Source Review Circumvention

Guidance to 3M - Maplewood, Minnesota

FROM:

John B. Rasnic, Director John & Jasus

Stationary Source Compliance Division

Office of Air Quality Planning and Standards

TO:

George T. Czerniak, Chief Air Enforcement Branch

Region V

This is in response to your memorandum dated March 16, 1992, requesting guidance on New Source Review (NSR) permitting for the Minnesota Mining and Manufacturing (3M) Center located in Maplewood, Minnesota. Specifically, you requested guidance on the applicability of the circumvention guidance to this source and other sources in similar situations. We also received from your staff more information about the modifications at 3M and we suggested that you issue a \$114 request to the source for more information. In early November, we received a copy of the response to the \$114 request dated October 30, 1992. We hope this memorandum provides sufficient guidance on permitting this source and other sources in similar situations.

Background

In your memorandum of March 16, 1992, you notified us that the 3M Center in Maplewood, Minnesota received four synthetic minor permits for modifications between October 1991 and March 1992. The permits for the four modifications combined allow emission increases of 33.6 tons per year (tpy) of particulates, 39.8 tpy of sulfur dioxide, 39.4 tpy of nitrogen dioxide, 22.0 tpy of carbon monoxide, and 119.2 tpy of volatile organic compounds. You learned during the Region's discussions with Minnesota that in 18 months, the source received 12 minor permits, and applied for several other minor permits. As a result, you indicated to the Minnesota Pollution Control Agency (MPCA) that 3M may be circumventing the Prevention of Significant Deterioration (PSD) regulations through these small projects. The MPCA, however, felt that these modifications were justified as separate modifications based on each 3M division pursuing its own research schedule.

EPAOAQ 0020602



Although it is somewhat unclear, the response to the §114 request arguably supports 3M's justification. Yet in light of criteria for identifying circumvention situations, as further explained below, the Stationary Source Compliance Division (SSCD) believes the source may not have been permitted properly for its modifications.

EPA Policy and Authority

EPA stated in the June 28, 1989 Federal Register notice on the definition of federally enforceable (54 FR 27274) and in its June 13, 1989 guidance on "Limiting Potential to Emit in New Source Permitting" that it is not only improper but also in violation of the Clean Air Act to construct a source or major modification with a minor source permit when there is intent to operate as a major source or major modification. Permits with conditions that do not reflect a source's planned mode of operation are sham permits, are void ab initio, and cannot shield a source from the requirement to undergo preconstruction review. 40 CFR §52.21(r)(4) requires application of NSR requirements to a source that asks for a relaxation of permit limits which would make the source major. EPA stated that it will require application of §52.21(r)(4) even where a source legitimately changes a project after finding it cannot comply with the operating restrictions which were taken in good faith.

Generally in "sham" permitting, a source attempts to expedite construction by securing minor source status through permits containing operational restrictions from which the source intends to free itself shortly after completion of construction and commencement of operation. Such attempts are treated as unlawful circumvention of the preconstruction review requirements. Similarly, attempts to expedite construction by securing several minor source permits and avoiding major modification requirements should be treated as circumvention. A memorandum dated September 18, 1989 from John Calcagni to William Hathaway stated this position (see Memorandum 4.42 in the NSR Guidance Notebook).

EPA stated in the 1989 Federal Register notice that it is not possible to set forth, in detail, the circumstances in which EPA considers an owner or operator to have evaded preconstruction review through minor permits, and thus subject itself to enforcement sanctions under §§113 and 167 from the beginning of construction. However, EPA will look to objective indicia to identify circumvention situations. For example, EPA provided examples of objective criteria in the June 13, 1989 guidance on limiting potential to emit. EPA also stated some criteria in the Federal Register notice which include: the filing of an application for a federal PSD permit at or near the same time as a state minor source permit; the economic realities surrounding a transaction; and projected levels of operation as portrayed to

lending institutions and other records of projected demand and output. EPA stated that where it appears obvious that a proposed source or modification, by its physical and operational design characteristics, could not economically be run at minor source levels for an appreciable length of time, EPA will consider minor source limits taken by the source unrealistic and sham.

Specific Criteria

Similar to the 1989 guidance, this memorandum provides criteria to permitting and enforcement authorities to apply when making determinations whether a source is circumventing major NSR through the minor modification process.

1. Filing of more than one minor source or minor modification application associated with emissions increases at a single plant within a short time period.

If a source files more than one minor source permit application simultaneously or within a short time period of each other, this may constitute strong evidence of an intent to circumvent the requirements of preconstruction review. Authorities should scrutinize applications that relate to the same process or units that the source files either before initial operation of the unit or after less than a year of operation. The September 18, 1989 memorandum from John Calcagni to William Hathaway states that two or more related minor changes over a short time period should be studied for possible circumvention.

2. Application of funding.

Applications for commercial loans or, for public utilities, bond issues, should be scrutinized to see if the source has treated the projects as one modification for financial purposes. If the project would not be funded or if it would not be economically viable if operated on an extended basis (at least a year) without the other projects, this should be considered evidence of circumvention.

3. Reports of consumer demand and projected production levels.

Stockholder reports, reports to the Securities and Exchange Commission, utility board reports, or business permit applications should be reviewed for projected operation or production levels. If reported levels are necessary to meet projected consumer demand but are higher than permitted levels, this is additional evidence of circumvention.

EPAOAQ 0020604

4. Statements of authorized representatives of the source regarding plans for operation.

Statements by representatives of the source to EPA or to State or local permitting agencies about the source's plans for operation can be evidence to show intent to circumvent preconstruction review requirements.

5. EPA's own analysis of the economic realities of the projects considered together.

EPA may determine that it is reasonable to expect that company management would coordinate the planning and execution of projects considering their intrinsic relationship with each other (physical proximity, stages of production process, etc.) and their impact on economic viability of the plant (scheduling down time in light of production targets, economies of scale, etc.).

Analysis of 3M-Maplewood

Although 3M applied for and received several minor source permits within 18 months, in response to the §114 request, 3M stated that independent divisions at the plant made the funding decisions for each independent project and that each project is independently viable. Thus, they suggest, the projects are not part of an attempt to circumvent preconstruction review. Minnesota have indicated that the divisions' actions should be reviewed separately and should not be treated as parts of a whole. However, the law plainly treats the Maplewood plant as one major emitting facility for NSR purposes. The NSR regulations do not provide special treatment because it is a research and development plant. Further, given the nature of this source, under normal conditions, a certain level of production or research development of new products can be expected. Although the NSR program generally allows sources to modify below significance levels without aggregating other contemporaneous net increases, sources cannot use the minor modification process to circumvent major modification requirements.

Where a source is permitted for several minor modifications that may in good faith be intended to be separate but result in the source's aggregate increases to be major even considering decreases over a short time period (e.g., one year or 18 months), the modifications may require major new source review. Such modifications could require NSR if they are viewed as being consistent with the source's overall production goals or plans for a short planning period. In other words, 3M should not benefit from the absence of a plant-wide production plan. Given the nature of the plant's work, 3M may be able to reasonably anticipate that modifications will occur within a relatively short period of time.

EPAOAQ 0020605

Reports on consumer demand and projected production or emission levels may provide evidence that this plant is expected to modify regularly in response to such demands or research needs. Some minimum level of research activity and commensurate emissions, source-wide, perhaps could be expected from year to year, as would be expected to keep the 3M plant productive or operable. These emissions and thereby modifications cannot be presumed to be independent given the plant's overall basic purpose to support a variety of research and development activities. Therefore, even though each research project may have been individually conceived and separately funded, it is appropriate to look at the overall expected research activity in assessing NSR applicability and enforcement.

Without regard to whether 3M intended to circumvent NSR requirements, this source and the State should discuss alternative permitting that could minimize the uncertainty of intent. Although we cannot require aggregation of all de minimis net increases, we believe that net increases should be aggregated for each "planning period" of the plant. One way to treat this source is to set a plant-wide emissions level, that can be raised only by going through major NSR. Recently, we worked with you and the MPCA to develop a plantwide emissions cap permit for a 3M facility in St. Paul. Although there are a number of concerns that must be addressed in such an approach, we believe that the source and the State would benefit from the certainty that such an approach provides.

If you have any questions regarding this matter, please contact Clara Poffenberger at (703) 308-8709.

cc: Karen Schapiro, OE
Greg Foote, OGC
Bill Lamason, AQMD
Air Division Directors
NSR contacts

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA)
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB))) Judge Bernard A. Friedman) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors v.)))
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY)))
Defendants.	<i>)</i>)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

Exhibit 8



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY REGION III 1650 Arch Street Philadelphia, Pennsylvania 19103-2029

PR 2 0 2010

Mr. Mark Wejkszner, Manager Air Quality Program Northeast Regional Office Pennsylvania Department of Environmental Protection 2 Public Square Wilkes-Barre, PA 18711-0790

Re: Northampton Generating Company PSD/NSR Analysis

Dear: Mr. Wejszner:

On March 16, 2009, the Pennsylvania Department of Environmental Protection (PADEP) submitted a draft plan approval for the Northampton Generating Company. On June 5, 2009, the Environmental Protection Agency (EPA) submitted comments on the draft plan approval, specifically regarding the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) applicability determination. In our comments we determined that there were errors in the NSR/PSD applicability analysis. Both the PADEP and Northampton responded to EPA's comments and submitted additional information on the project and the company's interpretation of certain provisions in 40 CFR 52.21. We have concluded our review of that information and would like to provide further clarification supporting our initial conclusions with respect to the project proposed in the plan approval for Northampton.

Background

The company operates a steam electric generating plant with one circulating fluidized bed (CFB) boiler that combusts anthracite culm and up to 50 percent by weight for any of the following: anthracite coal, bituminous coal, petroleum coke, paper processing residual, virgin wood chips, high carbon ash and tire-derived fuel. The current permit places a ton-per-hour cap on each of the above fuels (through a PSD analysis conducted in 2007), limits charging rate for all fuels combined to 105 tons per hour, and limits allowable heat input to 10,038,960 million British thermal units per year (MMBtu/yr) or 1146 MMBtu/hr. Continuous emissions monitors (CEMs) are in place for opacity, SO₂, NOx and CO. The source is located in a moderate nonattainment area for ozone and is considered a major source for NOx under NSR. The Northampton facility also is a major PSD source.

EPA Comments

The draft Plan Approval proposes to increase allowable heat input to 11,703,360 MMBtu/yr (1336 MMBtu/hr), keep the current annual permit limits for all pollutants except CO, and to change the CO limit from 753.4 tons per year (tpy) to 747.0 tpy to avoid being subject to PSD. An increase in heat input limits is proposed to produce more electricity.

Fine Particulate Matter (PM2.5)

On May 16, 2008, EPA published final regulations implementing NSR/PSD for PM2.5. Upon the effective date of the rule (July 15, 2008) Pennsylvania was required to immediately implement 40 CFR part 51 Appendix S for PM2.5 nonattainment areas and the revised 40 CFR 52.21 for attainment areas/unclassifiable areas. Subsequent to the effective date of the rule, EPA received a petition for reconsideration for various aspects of the rule, including grandfathering of applications submitted prior to the effective date for the purposes of using the PM10 surrogate policy. EPA has granted that petition and has also stayed the provision allowing grandfathering of applications. Therefore, all pre-construction permits issued in Pennsylvania after July 15, 2008, must implement the new rules and may no longer rely on the PM10 surrogate policy.

Neither the plan approval nor the Technical Review Memo for this project addressed the impact of the project on emissions of PM2.5. It is our assumption that PADEP and Northampton included only a PSD analysis for PM10 on the basis of EPA's former PM10 surrogate policy. As noted above, pre-construction permits in Pennsylvania may no longer rely on the surrogate policy and all plan approvals must include an NSR/PSD analysis for both PM10 and PM2.5.

PSD Applicability for CO

The company may elect to use either projected actual emissions or potential to emit (PTE) to estimate post-change emissions. CFR 52.21(b)(41)(ii)(d). The company elected to use projected actual emissions (PAE) in performing the actual-to-projected-actual applicability test as allowed under 40 CFR 52.21 (a)(2) (iv)(c). Note that for either approach baseline actual emissions (BAE) must be used and based on the information submitted, the BAE of carbon monoxide for the CFB appears to be 495.5 tpy. Below we provide general comments and analysis regarding the requirements of the applicability test using either PAE or PTE to estimate post-change emissions.

Applicability Test Using Projected Actual Emissions (PAE)

The PAE means the maximum annual rate, in tons per year, at which the CFB is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the CFB resumes regular operation after the project, or in any one of the ten years following that date, if the project involves increasing the emissions units design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit

would result in a significant emissions increase or a significant net emissions increase at the major stationary source. See 40 CFR 52.21(b)(41)(i).

Examples of factors that should be considered by the company in calculating PAE include, but are not limited to, projections of heat input, planned outages, projected hours of operation, and fuel mix. In addition, the company must consider all relevant information as outlined in 40 CFR 52.21(b)(41)(ii)(a) and (b), including historical operational data, quantifiable fugitive emissions, and emissions associated with startups, shutdowns, and malfunctions. For this CFB, which is a steam electric generating unit, the company is also required under 40 CFR 52.21(r)(6)(i) and (ii) to submit the bases of the applicability determination, including the baseline actual emissions, the PAE, the amount of emissions excluded under 40 CFR 52.21(b)(41)(ii)(c) and an explanation for why such amount was excluded, and any netting calculations, if applicable. For emissions excluded from the PAE, the company must demonstrate that such emissions could have been legally and physically accommodated before the project and are unrelated to the project. It is important to note that both of these requirements must be met for any emissions to be excluded. The company is required to submit all this information to the PADEP prior to beginning actual construction.

To our knowledge, the information used and other bases for the company's calculation of PAE has not been provided by the company to either the PADEP or to EPA Region 3. It is our understanding that the company has proposed a PAE level simply on the basis of calculating a level that would result in emissions increases from the project that are below the PSD significance levels. The company has not shared the expected utilization, fuel mix, demand growth, etc. and other information needed to properly make a projection of actual emissions. Therefore, EPA can not provide its views on this specific proposed applicability determination until this information is provided.

In order to properly use PAE to make an applicability calculation, the company first needs to project how they intend to operate after the change, including but not limited to how much the unit(s) will be used (demand growth) and the mix of fuels or other inputs necessary to achieve the projected use. The company must also identify the associated emissions rates based on the unit's operational capabilities following the change taking into account any legally enforceable restriction that could affect the hourly emission rate following the change. Then, based on the operation or utilization projections and the associated emission rates, the company should calculate the maximum expected post-change emissions in tons per year for each NSR regulated pollutant. For clarification, the following are the steps necessary to determine whether a project will result in a significant increase in emissions, using projected actual emissions.

Examples of legally enforceable restrictions are MACT, NSPS, and synthetic minor permit limits that restrict the level of the pollutant at issue.

Because PAE is based on the company's expected operations, it is generally inappropriate to rely on allowable emissions to project post-change emissions that the unit(s) is physically incapable of achieving. For example, if an emissions unit has a 700 tpy emissions limitation, but other physical or operational restrictions on the unit would preclude it from ever emitting at this level, then it would be inappropriate to use this level for PAE.

- Step 1. Calculate BAE for all existing units affected by the project.
- Step 2. Calculate the maximum annual emission rate in tons per year, over the five years (in some cases 10 years) after the change, considering all relevant information, including fugitive emissions and start-up, shut-down, and malfunctions. 52.21(b)(41)(i) and (ii)(a) and (b).
- Step 3. Examine the portion of post-change emissions and determine if any of such emissions above the baseline are not related to the project. If any of the emissions are not related, and the emissions unit(s) could have emitted at this level before the change if operated as projected, then those emissions may be excluded from the PAE calculation. This determination must consider such things as the currently permitted operational limits, emission rate limits, maximum firing rates, and allowable amount of each fuel that could be fired, and the expected mode of operations. A source may only subtract emissions from the maximum annual emission rate determined in Step 2 if those emissions could have been legally and physically accommodated during the baseline period and are unrelated to the change. 52.21(b)(41)(ii)(c).
 - Step 4. Subtract the BAE from the emissions derived in Step 3.
- Step 5. Compare the emissions increase from Step 4 to the significance level for each pollutant.

EPA has observed that a common mistake is to assume that a unit "could" have emitted up to its permitted amount during the baseline period and this is the amount that can be excluded from the PAE. This notion and any variation of this notion is incorrect. Excluded emissions from the PAE must satisfy two criteria. First, a facility can only subtract that portion of the projected actual emissions that the unit(s) could have already physically and legally emitted during the baseline period. For instance, a facility is permitted to burn coal with a sulfur content up to two percent but actually burns coal with one percent sulfur during the baseline period. The company bases the projected actual emissions on continuing to burn one percent sulfur coal. Emissions that can be excluded would be limited to emissions associated with burning one percent coal, regardless of the limit that would allow them to burn a higher sulfur coal. In other words, the emissions that "could have been accommodated" are not defined by all the many different operating conditions that could have occurred during the baseline period; rather emissions that may be excluded are limited by the proposed operating conditions used to project emissions into the future.

Second, the facility must be able to demonstrate that excluded emissions are completely unrelated to the project. As an example, a facility that proposes to switch from one fuel to another may be able to demonstrate that all of the projected emissions after the change could have occurred during the baseline period using the original fuel type. However, for this example none of the projected maximum annual emissions from the new fuel can be

excluded because all of the emissions that will occur after the project are related to the change in fuel.

Applicability Test using Potential to Emit (PTE)

40 CFR §52.21(b)(4) describes PTE as (among other things):

The maximum capacity of a stationary source to emit a pollutant under its physical or operational design. Any... operational limitation on the capacity of the source to emit a pollutant... shall be treated as part of its design if the limitation... is federally enforceable.

The PSD rules at 40 CFR §52.21(b)(41)(ii)(d) state that PTE may be used to determine an emissions increase in lieu of PAE. Furthermore, a facility that chooses to use PTE instead of PAE for its PSD applicability determination must choose to elect a synthetic minor permit limit to avoid triggering PSD if its PTE after the project results in a significant emissions increase. In the latter situation, the regulations provide no opportunity for a source to exclude emissions in the PTE calculations. Using CO from the CFB as an example, the synthetic minor limit needed to avoid PSD for CO would be derived as follows:

BAE + [less than significance level] = 496.55 tpy + < 100 tpy = < 596.55 tpy

The resulting synthetic minor limit must be legally and practicably enforceable, consistent with EPA's policy on PTE.

Impact of Other Pollutants on PSD Applicability

The company is seeking an increase in the heat input limits to accommodate changes in CO emissions over time. As explained in the additional information submitted by the company's consultant:

"The facility burns primarily anthracite culm and the quality of the culm available as different waste coal sites are reclaimed can vary significantly over time. As fuel quality degrades CO emissions increase. The facility contends that it needs its existing permit limit to accommodate the worst case fuel it may need to burn in the future. Indeed a review of the operating data for the plant shows that a 3 sigma analysis over a recent 39 month period shows the upper 3 sigma limit of CO emissions at 0.143 lb/MMBtu, within 35 tons of the existing permit limit at full capacity."

When this unit triggered PSD, the permit imposed BACT limits on CO of 0.15 lb/MMBtu, 172 lb/hr and 753.4 tpy. It appears that, rather than being unable to operate within the heat input restriction, the facility is actually concerned with being able to consistently comply with BACT as different waste piles are reclaimed. This is supported by the information submitted by the company. Baseline actual CO emissions for the unit are

496.55 tpy using a baseline period of 2006-2007. The average annual heat input for the same time period is 9,537,205 MMBTU. The facility is proposing to increase the heat input to 11,703,360 MMBtu, a difference of 2,166,155 MMBtu or 23 percent over the average baseline heat input. However, emissions are projected to increase over baseline by 50 percent.

Even more instructive as to the intent of this project, the company has used the actual-to-potential test for the other NSR regulated pollutants and is not proposing to change any of the current short or long term emissions limits, including the heat input limits. As the attached table shows, the increase in heat input is impossible to achieve without exceeding the permit limits for NOx and SO2, using either the actual average emissions factors or the permitted emissions factors for these pollutants. In fact, for the unit to increase the heat input to 11,703,360 MMBtu, the average NOx emission factor could not exceed 0.07 lbs/MMBtu, a 30 percent decrease from the permitted level and a 26 percent decrease from the actual average baseline emissions factor. Similarly, the average SO2 emission factor could not exceed 0.09 lb/MMBtu in order to accommodate the increase in heat input, which is 43 percent lower than the current permitted emission rate and 22 percent lower than the average baseline emission factor.

Although NSR/PSD applicability determinations are performed on a pollutant by pollutant basis, <u>any</u> restriction that would prevent a unit from actually reaching a projected level of utilization cannot be ignored. In this case, based on our analysis above, it appears the proposed increase in heat input is not achievable without exceeding the emission limits for NOx and SO2.

Conclusion

As proposed, the draft plan approval and underlying NSR/PSD applicability determination for the changes at the Northampton facility do not demonstrate compliance with federal NSR requirements. Therefore, the draft plan approval should not be issued. If you have any questions or would like to discuss these issues further, please don't hesitate to contact me at 215-814-3297 or Gerallyn Duke at 215-814-2084.

Diame McNally, Acting Associate Director

Office of Permits & Air Toxics

Attachment

Cc: Krishnan Ramamurthy, PADEP

Northampton Generating Station

Year	Actual	Total	Average	Permit limit	PTE -	PTE-	Current
	Emissions	Annual	Actual	(lb/MMBtu)	Average	Permitted	Annual
	(tons/yr)	Heat	Emission		Emission	Emission	Limit
		Input	Factor		Factor	Factor	(tons/yr)
		(MMBtu)	(lb/MMBtu)		(tons/yr))	(tons/yr)	
			<u> </u>	VOx			
2005	401.4	8732180	0.092	0.1	538.0	585.2	449.5
2006	419.6	10003990	0.084	0.1	490.9	585.2	449.6
2007	384.0	9070420	0.085	0.1	495.5	585.2	449.6
SO2							
2005	503.1	8732180	0.115	0.129	674.3	754.9	557.8
2006	534.5	10003990	0.107	0.129	625.3	754.9	557.8
2007	485.4	9070420	0.107	0.129	626.3	754.9	557.8

IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	
Plaintiff,	Civil Action No. 2:10-cv-13101-BAF-RSW
and)) Judge Bernard A. Friedman
NATURAL RESOURCES DEFENSE) Judge Demard A. Friedman
COUNCIL, and SIERRA CLUB) Magistrate Judge R. Steven Whalen
Plaintiff-Intervenors)
v.	
DTE ENERGY COMPANY, and)
DETROIT EDISON COMPANY)
Defendants.)

PLAINTIFF'S MEMORANDUM IN SUPPORT OF ITS MOTION FOR PARTIAL SUMMARY JUDGMENT ON THE LEGAL STANDARDS AT ISSUE IN THIS CASE

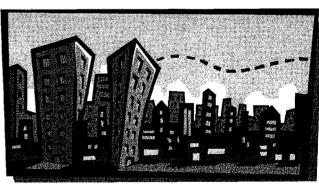
Exhibit 9



Workbook

A Practical Guide to Prevention of Significant Deterioration







Michigan Department of Environmental Quality Air Quality Division

October 2003

Jennifer M. Granholm, Governor Steven E. Chester, Director www.michigan.gov/deq 800-662-9278 AUTHORITY: PA 451 of 1994, as amended

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Michigan Department of Environmental Quality





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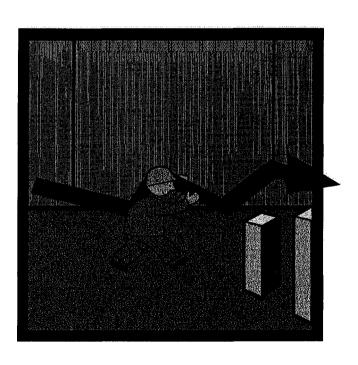
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CHAPTER 4 APPLICABILITY TESTS BASED ON EMISSIONS CHANGES

In This Chapter:

- Actual to Potential Test
- Actual to Projected Test
- Recordkeeping and Reporting Requirements
- Permit Content
- Examples



CHAPTER 4: APPLICABILITY TESTS BASED ON EMISSIONS CHANGES

Having established the methodology for determining Baseline Actual Emissions in Chapter 3, we are ready to take on the two most common PSD applicability determinations — the Actual to Potential Emissions Test (A2P) and the Actual to Projected Actual Emissions Test (A2A).

Other applicability tests exist for special categories of sources. The Clean Unit test applies to changes at emission units that have been designated as Clean Units. Clean Units will be covered in Chapter 5. For facilities operating under a Plantwide Applicability Limit (PAL) PSD does not apply at all unless the facility wishes to increase its emissions above the PAL. PAL's will be covered in Chapter 6.

As outlined in Chapter 2, PSD applicability for changes that involve only new emission units is determined using the A2P. For changes that involve only existing emission units, PSD applicability is determined using either the A2A or the A2P. PSD applicability for changes that involve some new and some existing emission units is determined using the hybrid test. We will cover these three applicability tests in order – Actual to Potential (A2P), Actual to Projected Actual (A2A) and Hybrid.

Actual to Potential Emissions Test

The Actual to Potential Emissions Test (A2P) can be used for projects involving new or existing emission units. For new emission units, it is mandated as the only method for determining PSD applicability. The A2P involves comparing the potential to emit of each emission unit affected by a project to its BAE. The A2P is used to determine the emissions increase from the proposed project — not the net emission increase. It is only used for the first half of the two-step PSD applicability determination.

Helpful Hint:
Be sure to carefully define the project. Identify ALL affected emission units.

Potential to emit is defined in 40 CFR 52.21 (b)(4) as:

The maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

According to this definition, an emission unit's permit-limited emissions (i.e., allowable emissions) after the proposed project represent its potential to emit. Therefore, many facilities choose to accept permit limits in order to avoid becoming subject to PSD. Permit limits that accomplish this process of limiting out of PSD are called "Synthetic Minor" limits. Projects that are limited out of PSD applicability are also referred to as

"Synthetic Minor." Future changes to a Synthetic Minor source or project may result in a re-evaluation of the original PSD applicability determination.

If the sum of the post-project potential emissions for all affected emission units exceeds the BAE by greater than the appropriate PSD applicability threshold, the proposed project may be subject to PSD depending on the magnitude of the net emissions increase. If the potential emissions of all affected emission units after the proposed project exceed the BAE by less than the appropriate applicability threshold, no further evaluation is necessary – the project is not subject to PSD.

The A2P is the traditional applicability determination method used by all sources prior to the March 3, 2003 NSR reforms. This method, when applied to existing emission units tends to overstate the magnitude of the emission increase associated with a particular project. The permitted, allowable emissions after a project do not always represent the emissions increase that results from that change. It often represents the increase from that change plus any production capacity that was not being used during the baseline period.

For example, consider a natural gas fired boiler that emits nitrogen oxides (NO_X) at 75 pounds per hour and has consistently operated 7200 hours per year. This boiler will generate NO_X emissions of 270 tons per year. The boiler's permit limits emissions to the equivalent of 8760 hours per year, or 328.5 tons per year. If a project were undertaken that would increase the boiler's emission rate from 75 to 80 pounds per hour, the potential emissions would increase from 328.5 to 350.4 tons per year.

For this project, the A2P would measure the increase as 350.4 tons per year (potential) minus 270 tons per year (BAE) or 80.4 tons per year. However, because the increase in hourly emissions will not automatically result in an increased boiler utilization, most of the calculated difference between potential emissions and BAE result from unused capacity utilization (i.e., operation beyond 7200 hours per year).

This aspect of the A2P has frustrated industry for many years. Even small changes can be counted as major modifications and subject to PSD. Therefore, in its reforms to NSR, USEPA has developed another applicability test - the Actual to Projected Actual Emissions Test (A2A).

Actual to Projected Actual Emissions Test

Do not Forget:

To properly define the project. Identify ALL affected emission units.

The Actual to Projected Actual Emissions Test (A2A) is a more complicated evaluation than the A2P. The A2A was developed in an effort to evaluate PSD applicability based only on the emission increases that are attributable to a proposed project. Other increases, such as emission increases due to changes in business demand (i.e., capacity utilization) unrelated to the proposed project, are not counted. However, increases in capacity utilization that will result from the proposed project are counted. For example, when a proposed project is necessary in order to

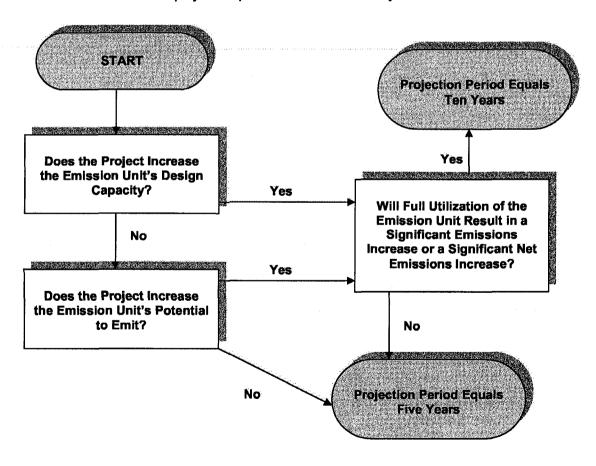
handle a projected increase in business demand, then the emissions associated with that increased capacity utilization are attributed to the project.

The A2A involves comparing projected actual emissions from all affected emission units with the BAE from the affected emission units. The A2A cannot be used with new emission units. Because this applicability test involves estimates of future business activity, it requires a substantial amount of documentation. The future estimates must be available in public documents, or confidential business information, on which the facility is basing its business decisions. Future estimates generated for the purposes of the applicability test are not acceptable.

The procedures for determining projected actual emissions are set forth in the PSD regulations under 40 CFR 52.21 (b)(41).

Step 1 – Determine the projection period

The projection period begins on the date the affected emission unit resumes regular operation after completion of the proposed project. Typically, the projection period must encompass the first <u>five</u> years after resuming regular operation. Under certain circumstances, the projection period will encompass the first <u>ten</u> years after resuming regular operations. The following flow chart outlines the decision-making process to determine whether the projection period will be five or ten years:



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Resuming regular operation means that construction and initial shakedown of the modified emission unit has been completed. The PSD regulations, in general, allow 180 days to be counted as the initial shakedown period.

Step 2 - Develop an initial projection

The actual annual emissions associated with the projected level of business activity in each year of the projection period must be determined. The projected level of business activity must be based on existing, available information as described above. Documentation must be made available to the MDEQ to support any projection.

Projections may be based on:

- Historical operating data (i.e., trends). Documentation must be provided to support the projected continuation of any trend throughout the projection period.
- The company's own representations. Existing available documentation must be provided demonstrating that the company has made such representations to the public, to its shareholders, to its board or to its parent company.
- The company's expected business activity and the company's highest projections
 of business activity. As before, existing available documentation must be
 provided demonstrating that the company has established such expectations and
 made such projections for business purposes.
- The company's filings with state and federal regulatory authorities. Copies of such filings must be provided.
- Any other enforceable documentation that may include projections of business activity during the projection period (e.g., compliance plans).

The projection is an estimate of business activity. Once established, the actual annual emissions that correspond to that level of business activity must be calculated. The absence of adequate documentation will nullify the projection. In such a situation, the A2A will not be allowed and the facility must use the A2P.

Step 3 – Adjustments to the initial projection

Fugitive emissions, if they can be quantified, must be included in the projected actual emissions. Additionally, emissions associated with startups, shutdowns and malfunctions must be included in the projected actual emissions.

Step 4 - Excluded emissions

Emissions increases that are not related to the specific proposed project may be excluded from the projected actual emissions. These emissions can be identified as those that:

Could have been accommodated during the selected 24-month baseline period by the pre-modified emission units

And

Are not related to the proposed project

Emissions that could have been accommodated are not the baseline period allowable emissions for the affected emission units. They are the level of emissions from the premodified emission units operating at the projected level of business activity. Any permit or regulatory restrictions on the operation of the affected emission units must be taken into consideration when determining excludable emissions.

Determining whether certain emissions increases are related to the proposed project will be a case-by-case determination. For example, if a widget manufacturing process is being modified to accommodate the production of gadgets as well as widgets, then any projected emissions that will result from the continued manufacture of widgets are not related to the modification – they would have occurred anyway.

Step 5 – Determine projected emissions increase

Projections must be developed for each year, not necessarily a calendar year, during the

projection period. Each of these projected levels of actual annual emissions must be compared with the greater of: the excludable emissions; or, the BAE to determine the magnitude of the resulting emissions

Reminder:

A2P = Actual to Potential applicability test
A2A = Actual to Projected Actual applicability test

increase. PSD applicability will be based on the highest emissions increase calculated in this way (i.e., the highest projected increase).

A2A Recordkeeping and Reporting Requirements

Prior to beginning actual construction on a proposed project, a facility must record the following information:

- A description of the project;
- Identification of each affected emission unit:
- A description of the applicability test used; including,
 - o The BAE;
 - o The projected actual emissions;
 - o The amount of excluded emissions:
 - o The reason for excluding that amount; and,
 - o Any netting calculations, if applicable.

The PSD regulations (i.e. 40 CFR 52.21(r)(6)) only require this information to be recorded if there is a "reasonable possibility" that the project may result in a significant emissions increase. Further, the PSD regulations only require this information to be submitted to the MDEQ for EUSGUs. However, the MDEQ's minor source permitting program – Rule 201 – requires this information to be submitted for all sources as part of a complete Permit to Install application before beginning actual construction on the proposed project.

After resuming normal operation following completion of the project, the PSD regulations also require the facility to monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that are emitted by any of the affected emission units. In addition, annual emissions, in tons per year, are required to be calculated at the end of each year following the date that normal operation resumes after completion of the project. These monitoring and emission calculation requirements shall continue for each year of the projection period.

For EUSGU's, a report of each affected emission unit's annual emissions must be submitted to the MDEQ within 60 days after the end of each year of the projection period. For non-EUSGU's, a report is only required for those years in which actual annual emissions exceed the BAE by more than the significance threshold and differ from the pre-construction projected emissions. Such a report for non-EUSGU's must include:

- The name, address and telephone number of the facility:
- The calculated annual emissions; and,
- Any other information the owner or operator wishes to include in the report (e.g., an explanation why the emissions differ from the projection).

All such information, whether it is required to be submitted to the MDEQ or not, is required to be maintained on site and made available for review upon request, by the MDEQ.

The circumstances that lead to the submittal of this report (i.e., actual emissions exceed BAE by more than the significant threshold and differ from the projection) do not automatically constitute a violation of PSD. There are many legitimate circumstances under which this could occur. The most obvious is that business growth exceeds the

projected growth rate. In this case, the fact that business turns out to be better than expected is not a violation of PSD. The growth, if it had been accurately projected, would have resulted in excluded emissions and the conclusions of the original PSD applicability determination would not have changed. The submittal of this report will only trigger an evaluation of the circumstances to determine if a PSD violation may have occurred.

Permit Content

Facilities using the A2A will be required by permit conditions to conduct the monitoring and emission calculations, and to keep and maintain the records described above. The projected actual emissions will not be instituted as an enforceable permit requirement. However, it will likely find its way into the permit for informational purposes only.

EXAMPLES:

Following are several examples to help clarify the A2A. These examples are built on the boiler example used above to illustrate the A2P. The boiler emits NO_X at 75 pounds per hour and has consistently operated very near 7200 hours per year throughout the tenyear baseline look back period. The BAE is: 7200 hr/yr x 75 lb/hr x 1 ton/2000 lb = 270 tons/yr.

The proposed project will increase the hourly emission rate from 75 to 80 pounds per hour.

For all of the following examples, the first step, determining the projection period is the same. The proposed project increases the emission unit's potential to emit from 75 to 80 pounds per hour. Using the A2P, operation of the emission unit for the allowed 8760 hours per year would represent an emissions increase greater than the 40 ton per year significant threshold:

```
8760 hr/yr x 80 lb/hr x 1 ton/2000 lb = 350.4 tons/yr

- 7200 hr/yr x 75 lb/hr x 1 ton/2000 lb = 270.0 tons/yr

= 80.4 tons/yr
```

Because the potential emissions increase and full utilization would result in a significant emissions increase, the projection period must be ten years.

Example 1:

Step 2 - Develop an initial projection

The company utilizes the consistent historical operating trend to project a continued boiler utilization, after the project, of 7200 hours per year. Documentation is provided showing, in addition to the past trend, that future natural gas contracts indicate the company is not intending any significant increases in boiler utilization. Further, internal company correspondence with its corporate headquarters demonstrates no growth is

Example 1 continued:

projected. Therefore, the initial projected actual emissions are:

 $7200 \text{ hr/yr} \times 80 \text{ lb/hr} \times 1 \text{ ton/}2000 \text{ lb} = 288.0 \text{ tons/yr}$

Step 3 – Adjustments to the initial projection

Continuous NO_X emission monitor records demonstrate that the emission unit does not generate any excess emissions during the few startups and shutdowns it undergoes each year. Further, no malfunctions have occurred in any of the past ten years. Therefore, no adjustments to the initial projected emissions are necessary.

Step 4 - Excluded emissions

Excluded emissions are those that are unrelated to the modification and were capable of being accommodated by the pre-modified emission unit. These are, generally, the level of emissions that would have been emitted anyway – without the modification. This boiler was capable of accommodating emissions of 75 pounds per hour. For this boiler, the first 75 pounds per hour at the projected level of capacity utilization are unrelated to the modification. Therefore, there are excludable emissions in the amount of:

$$7200 \text{ hr/yr} \times 75 \text{ lb/hr} \times 1 \text{ ton/}2000 \text{ lb} = 270.0 \text{ tons/yr}$$

In this situation, the excludable emissions are the same as the BAE. In the examples to follow, this will not always be true.

Step 5 - Determine projected emissions increase

Since the excludable emissions equal the BAE, the projected increase is determined by:

$$288.0 \, \text{tons/yr} - 270.0 \, \text{tons/yr} = 18 \, \text{tons/yr}$$

In this case, the proposed modification is less than the significant threshold and is not subject to PSD – netting is not required:

Example 2:

Step 2 - Develop an initial projection

In this scenario, the company projects that their business will grow a total of five percent over the next ten years. They document their projection with copies of an internal report provided to their parent company and their parent company's stockholder prospectus.

Example 2 continued:

both showing a five percent growth over the next ten years for this division of the company.

The projected level of emissions is equal to:

$$7200 \text{ hr/yr} \times 1.05 = 7560 \text{ hr/yr}$$

7560 hr/yr x 80 lb/hr x 1 ton/2000 lb = 302.4 tons/yr

Step 3 - Adjustments to the initial projection

Continuous NO_X emission monitor records demonstrate that the emission unit does not generate any excess emissions during the few startups and shutdowns it undergoes each year. Further, no malfunctions have occurred in any of the past ten years. Therefore, no adjustments to the initial projected emissions are necessary.

Step 4 - Excluded emissions

Excluded emissions are those that are unrelated to the modification and were capable of being accommodated by the pre-modified emission unit. These are, generally, the level of emissions that would have been emitted anyway – without the modification. This boiler was capable of accommodating emissions of 75 pounds per hour. For this boiler, the first 75 pounds per hour at the projected level of capacity utilization are unrelated to the modification. Therefore, there are excludable emissions in the amount of:

 $7560 \text{ hr/yr} \times 75 \text{ lb/hr} \times 1 \text{ ton/2000 lb} = 283.5 \text{ tons/yr}$

In this situation, the excludable emissions are greater than the BAE

Step 5 - Determine projected emissions increase

Since the excludable emissions are greater than the BAE, the projected increase is determined by:

In this case, the proposed modification is less than the significant threshold and is not subject to PSD – netting is not required.

Example 3:

Step 2 - Develop an initial projection

In this scenario, the company projects that their business will grow a total of ten percent over the next ten years. They document their projection with copies of an internal report provided to their parent company and their parent company's stockholder prospectus.

Example 3 continued:

both showing a ten percent growth over the next ten years for this division of the company. The documentation also shows that the expected growth is due to the introduction of a new product. The manufacture of the new product is the reason the boiler is being modified.

The projected level of emissions is equal to:

 $7200 \text{ hr/yr} \times 1.10 = 7920 \text{ hr/yr}$

7920 hr/yr x 80 lb/hr x $\frac{1 \text{ ton}}{2000 \text{ lb}} = \frac{316.8 \text{ tons/yr}}{2000 \text{ lb}}$

Step 3 - Adjustments to the initial projection

Continuous NO_x emission monitor records demonstrate that the emission unit does not generate any excess emissions during the few startups and shutdowns it undergoes each year. Further, no malfunctions have occurred in any of the past ten years. Therefore, no adjustments to the initial projected emissions are necessary.

Step 4 - Excluded emissions

Excluded emissions are those that are unrelated to the modification and were capable of being accommodated by the pre-modified emission unit. These are, generally, the level of emissions that would have been emitted anyway – without the modification. Because the increased utilization rate is due to the modification, it cannot be excluded. Therefore, the excludable emissions are equal to the BAE in the amount of:

7200 hr/yr x 75 lb/hr x 1 ton/2000 lb = 270.0 tons/yr

In this situation, the excludable emissions are equal to the BAE

Step 5 - Determine projected emissions increase

Since the excludable emissions are equal to the BAE, the projected increase is determined by:

316.8 tons/vr - 270.0 tons/vr = 46.8 tons/vr

In this case, the proposed modification results in a significant emissions increase. A netting analysis must be conducted to determine if it also results in a significant net emissions increase before determining whether or not it is subject to PSD.

Prepared by: Steve Zervas

Air Quality Division

Michigan Department of Environmental Quality